

PETROLEUM CONSERVATION IN OHIO

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Late in 1963, an oil boom got underway in Morrow County, Ohio, that was reminiscent of the final years of the 19th century, when Ohio was one of the nation's leading oil producers, supplying in one year (1896) more than one-third of all the oil produced in the country.¹

In 1964, 2665 new wells were drilled in 70 of the 88 counties in the state; 1106 of these wells secured production, for a successful completion average of 41.5 per cent; production was obtained in 41 counties. In Morrow County alone, 1342 wells were drilled, 431 of which secured production. Crude oil production increased to 15,580,000 barrels per year, putting Ohio 17th among oil producing states, and 37,713 million cubic feet of gas were produced, placing the state in 15th position among gas producing states.²

Also reminiscent of the 19th century was the 1963 status of Ohio's petroleum conservation laws. Such laws were virtually nonexistent. Until March of 1964 there were no well-spacing regulations in the state at all, and when instituted in that month, the regulations merely restricted drilling to 10-acre drill sites. Town-lot drilling was a common practice.³

Happily, in 1965 the Ohio Legislature adopted a conservation law that provides the authority and means to accomplish effective petroleum conservation.⁴ While we shall have occasion to criticize some of its details, the act in general makes a number of positive contributions to the cause of oil and gas conservation. It establishes a regulatory commission which is indirectly empowered to prevent waste, and is directly authorized to regulate drilling, to establish state-wide well-spacing rules as well as special field rules (both without statutory limits on the size of drilling units) and to compel pooling and unitization.

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¹ Ohio Legislative Serv. Comm'n, Oil and Gas Law in Ohio, Staff Research Report No. 63, at 12 (1965). [Hereinafter cited as Staff Research Report].

² XXIV Oil and Gas Compact Bull. 62-63 (1965). The bulletin gives the successful completion average as 45.25%, but this appears as a mistake from the figures given.

³ *Id.* at 63.

⁴ Chapter 1509 of the Ohio Revised Code, signed by the Governor July 16, 1965, and effective 90 days from that date. The act was based on Sub. H.B. No. 234, introduced by an *ad hoc* legislative committee chaired by Representative Armstrong.

It is the purpose of this article to examine the substantive provisions of the statute in some detail and to comment more generally on the administrative structure and procedure for implementing and enforcing the conservation regime.

I. THE REGULATORY COMMISSION

The act creates a Division of Oil and Gas within the Department of Natural Resources⁵ and delegates to the chief of the division the power and duty to enforce the provisions of the act and to make additional rules for its administration and implementation.⁶ The chief has the principal responsibility for administering the conservation law, but two other agencies are delegated some power in connection therewith. One of these, the Technical Advisory Council on Oil and Gas, has no rule-making, adjudicating, or enforcement powers, except with respect to well-spacing. Its main function is to advise the Chief of the Division of Oil and Gas, although it may participate in whatever hearings the chief may hold and the chief may delegate to it some of his statutory powers.⁷ In two instances, the Technical Advisory Council has independent power of its own: it must approve both state-wide well-spacing orders⁸ and special well-spacing orders applicable to particular reservoirs.⁹ Since this veto power over well-spacing orders is important, we will pause to examine the composition of the Technical Advisory Council. It has seven members, appointed by the Governor and approved by the senate. Three members are to be independents operating primarily in Ohio; three more are to represent operators with substantial Ohio interests but who also have substantial interests in at least one other state. The seventh member is to represent the public. All but the latter must have had a minimum of five years of practical or technical experience in the industry and none of these six may represent more than one company or operator. Office terms are three years long and are staggered.¹⁰

How the council will discharge its important duty of review and approval of spacing orders is subject to speculation. Much will depend, of course, on the identity of its members, but the design seems to give some power to independent operators who, on the basis of past history, may be expected to favor denser spacing

⁵ Ohio Revised Code Ann. § 1509.02 (Page Supp. 1965) [Hereinafter cited by the section].

⁶ Section 1509.03.

⁷ Section 1509.38.

⁸ Section 1509.24.

⁹ Section 1509.25.

¹⁰ Section 1509.38.

than major operators ordinarily desire. On the other hand, except possibly for the public member, no representation is given to land-owners, who are the most vigorous proponents of intensive drilling. One may be permitted to hope for—perhaps even expect—a sensible spacing policy based on the area that can be efficiently drained by a single well. One could have been surer of such a policy had not the legislature deleted from the bill the provision adopting efficient drainage as the spacing standard.¹¹

In addition to the Technical Advisory Council, the act creates an Oil and Gas Board of Review of five members appointed by the Governor (without concurrence of the senate) for staggered terms of five years. One member is to represent the major companies, one the independent companies, one is to be "learned and experienced in oil and gas law" (presumably a licensed lawyer since experience is required), one a geologist, and one a person "who, by reason of his previous vocation, employment, or affiliations, can be classed as a representative of the public"—a vague classification which might stump even a sociologist but which may in practice turn out to be a deserving public servant whose worth went unappreciated at the polls. Not more than three can be members of the same political party.¹² The board hears appeals from orders of the Chief of Division of Oil and Gas.

It may be a formidable job to obtain qualified men for the board as the statute places the niggardly limit of 20 dollars a day on their compensation.¹³ It is regrettable that membership on the board was not made more attractive, for with the proper personnel it could have had an influence on the regulatory process. The powers of the board are broad, for it can enter the orders that it finds the Chief of the Oil and Gas Division should have entered.¹⁴ With this kind of power and with the expertise that the statutory qualifications contemplate, the board might have become the preferred avenue of appeal, thus serving as a knowledgeable check on the Chief of the Oil and Gas Division and relieving the inexperienced courts of much of the burden of overseeing the work of the division. Perhaps this may still prove to be the case, as public-spirited, disinterested-yet-qualified citizens come forward to volunteer their services. We, however, are inclined to the view that you get what you pay for.

¹¹ Section 1509.22 of the draft version of the bill provided: "The size of the drilling units shall not be smaller than the maximum area that can be efficiently and economically drained by one well. . . ."

¹² The organization of the board is set forth in § 1509.35.

¹³ Section 1509.35. This is down \$5.00 from the rate of pay set by the draft bill.

¹⁴ Section 1509.36.

With this brief introduction to the regulatory agency, we turn now to an examination of the substantive provisions of the statute, after which we will consider administrative procedures (including appeals). The article concludes with some comments on deficiencies in the act and some suggestions for improvement on it.

II. SUBSTANTIVE STATUTORY PROVISIONS

A. *General*

The definitions section of the statute defines waste fairly broadly to include physical waste ("as such term is generally understood in the oil and gas industry"), waste of reservoir energy, inefficient storage of petroleum, and drilling and operation of wells so that the amount of hydrocarbons ultimately recoverable by prudent operation is reduced.¹⁵

Curiously, the statute has no provision explicitly granting power to the Chief of the Oil and Gas Division to make rules for the prevention of waste. It would appear, however, that a back-handed grant of power is made in section 1509.20, which requires operators to use "every reasonable precaution in accordance with the most approved methods of operation to stop and prevent waste" Since the chief has power to make rules and regulations to implement and enforce the statute,¹⁶ he can, we believe, promulgate regulations specifying particular duties created by section 1509.20. The only substantive limitations on this power are those inherent in the statutory definition of waste, those inherent in the statutory duty to use "the most approved methods of operation,"¹⁷ and those set forth in specific provisions elsewhere in the statute. The first two limitations have minor significance, since waste is broadly defined and since the duty of operators to prevent waste is measured by a rigorous standard of "most approved methods." There are, however, a number of specific statutory provisions governing operations, and they, of course, override the chief's rule-making power. For example, the statute expressly permits the flaring of casinghead gas where there is "no economic market at the well for the escaping gas."¹⁸ This is an unfortunate provision, for it deprives the agency of the ability to use shut-down orders to force gas connections to a field, a device that agencies in other states have successfully employed.¹⁹

¹⁵ Section 1509.01(H).

¹⁶ Section 1509.03.

¹⁷ Section 1509.20.

¹⁸ *Ibid.*

¹⁹ The Texas Railroad Commission has waged a vigorous fight to prevent the flaring of casinghead gas. For example, in the Spraberry Field the commission shut

In addition to prohibiting waste, the statute prohibits pollution of surface and ground water by oil and gas operations and delegates rule-making power to the chief to accomplish this objective. Similarly, the chief is authorized to promulgate safety rules to safeguard against hazards to life, limb, and property.

B. *Drilling permits*

Drilling permits from the chief are required for drilling a new well, deepening an existing well, reopening a well, or plugging back a well to a different source of supply.²⁰ Applications for permits are required to contain the information one would expect for the purpose, the only unusual requirement being that of supplying the names and addresses of royalty owners.²¹ A surety bond must be posted before the permit can issue.²² Owing to the prevalence of coal mining in Ohio, the statute contains detailed provisions regulating the drilling of oil and gas wells close to mines. We will not examine those provisions beyond noting that an oil and gas operator who drills wells within specified, short distances from coal mines, must give notice to the mine operator, who is granted an opportunity to object to the issuance of a permit.²³ Completion reports are required for all wells.²⁴ In addition, after a six months interval (allowed presumably to preserve secrecy) electrical, radioactivity, and geophysical logs run during drilling must be filed with the division.²⁵ For wells capable of producing oil or gas, annual production reports are required.²⁶

A curious provision is found in section 1509.12: "Unless written permission is granted by the chief . . ., no owner of any oil well shall permit said well to stand more than six months without diligently pumping or flowing same." The purpose would not appear to be the same as that of the next following provision, requiring the

down all producing wells until the casinghead gas produced from the field could be put to beneficial use. While this order did not survive attack in the Texas Supreme Court, *Railroad Comm'n v. Rowan Oil Co.*, 152 Tex. 439, 259 S.W.2d 173, 2 O. & G.R. 616 (1953), the court left it open to the commission to accomplish the same result by limiting oil production to the amount that would produce only that volume of gas for which there was a market. Within five years the commission had accomplished its purpose. See Sullivan, *Conservation of Oil and Gas, A Legal History*-1958, at 232-235, 237, 243 (1960). See also Jones, *The Spraberry Decision*, 32 Texas L. Rev. 730 (1954).

²⁰ Section 1509.05.

²¹ Section 1509.06(C).

²² Section 1509.07.

²³ Section 1509.08.

²⁴ Section 1509.10.

²⁵ *Ibid.*

²⁶ Section 1509.11.

plugging of gas wells that have ceased to be productive and have not been operated for six months. The latter, a familiar requirement, is aimed at fire hazard from escaping gas and at pollution of sub-surface strata. The former does not require plugging when the oil supply is exhausted but seems rather to establish an absolute statutory duty of operation as a substitute, in this circumstance, for the common-law duty of prudent operation. Particular sanctions for the violation of this statutory duty are not prescribed in the act. Query, whether the chief could obtain a mandatory injunction to operate the well under section 1509.04, the wording of which seems to contemplate restraining orders, not affirmative orders to act. Query further whether the provisions of section 1509.99 imposing fines for violation of the statute are applicable to the failure to produce.

In addition to drilling permits, the statute requires a permit for plugging and abandoning wells, and after plugging, an abandonment report. Supervision of plugging operations by state officials is contemplated by the statute, which specifies plugging methods in considerable detail.²⁷ Similarly the statute²⁸ contains detailed provisions on methods of drilling wells through coal mines. One wonders why the legislature thought it necessary or desirable to include detailed legislation on a subject that seems readily adoptable to treatment by rules issued by the regulatory agency.

C. *Well spacing*

Two sections of the act relate to this subject, sections 1509.24 and 1509.25. The former authorizes state-wide spacing orders, which may be issued by the chief upon approval of the Technical Advisory Council on Oil and Gas. The standard governing the exercise of this power to establish minimum-sized drilling units is "conserving oil and gas reserves and the safety of persons."

Section 1509.25 authorizes the issuance of special well-spacing orders for particular reservoirs. Such orders may be issued, after notice and hearing, upon the chief's own initiative or upon application by an operator. The substantive requirements for the issuance of the order are:

- (1) Findings that the pool can be defined with reasonable certainty,
- (2) Findings that the pool is in "the initial state of development" (a phrase not defined in the statute),

²⁷ Sections 1509.15-17, 1509.19.

²⁸ Section 1509.18.

- (3) Findings that departure from the state-wide order under section 1509.24 is reasonably necessary to protect correlative rights or to conserve oil and gas, and
- (4) Written approval of the Technical Advisory Council on Oil and Gas.

The order itself must provide for uniform spacing, except for the discovery well, and other wells already drilled or being drilled.

A draft version of the bill declared that "the size of drilling units shall not be smaller than the maximum area that can be efficiently and economically drained by one well" This provision does not appear in the act, but its omission does not necessarily prevent the chief from adopting such a standard as the guideline for making field rules.

To this point the spacing provisions of the statute are fairly typical of conservation statutes generally. However, the last paragraph of section 1509.25 is somewhat mystifying. It provides: "Nothing in this section shall permit the chief to establish drilling units in a pool by requiring the use of a survey grid coordinate system with fixed or established unit boundaries."

If we interpret this provision correctly, it forbids the use of any grid system, including the United States Government Survey (which covers much of Ohio), as the basis for establishing drilling units by special orders directed to particular pools. We can think of no good reason for such a prohibition. The Report of the Committee to Study Oil and Gas Laws in Ohio (the Armstrong Committee) recommended that the statute "allow the administrative agency to use property lines, government survey lines, or a grid in setting out the drilling units"²⁹ Other states having the United States Government Survey regularly employ it in spacing orders, and Texas, which does not have the Survey, uses both private grid surveys and commission-established grid patterns in its spacing orders.

Possibly the paragraph is intended to have a narrower meaning. It could be interpreted to mean that the chief shall not employ a *new* grid system but shall make use of existing surveys and property lines. This interpretation would solve the problem for most of Ohio, but would leave the Virginia Military District, which has no rectangular survey, outside its provisions. At present, there is little or no petroleum activity in the latter area.

²⁹ Ohio Legislative Serv. Comm'n Report of the Comm. to Study Oil & Gas Laws in Ohio 3 (1964). The Staff Research Report makes the same recommendation.

The preferable solution to the problem is to repeal the paragraph entirely, leaving to the chief the discretion to establish drilling units by reference to whatever survey lines seem convenient to him.

Wells may be drilled on undersized or irregularly shaped tracts of land as exceptions to both the state-wide spacing rule and to special field orders.³⁰ For an exception to be granted, the applicant must show that:

- (1) he is unable to enter a voluntary pooling agreement (since almost anyone can get into a voluntary pooling agreement upon some kind of terms, we expect the chief and the courts to construe this clause to contain an implied standard of reasonableness, so that the requirement is met if the land cannot be pooled on reasonable terms) ;
- (2) he would be unable to participate under a mandatory pooling order ;
- (3) he would otherwise be precluded from producing oil and gas from his tract because of spacing or distance requirements.

The safety valve provided by this section is useful, but we should not expect it to be invoked often since voluntary and compulsory pooling should take care of most undersized and irregular tracts. Reduction of the allowable production from such exception tracts³¹ should eliminate much of the incentive for seeking exceptions.

D. *Prorationing*

Section 1509.40 would seem to flatly forbid limitations on production. In the broadest possible terms the section provides that "no authority granted in Chapter 1509 of the Revised Code shall be construed as authorizing a limitation of production of oil or gas for any reason whatsoever." The only exception is for undersized tracts to protect correlative rights. Under section 1509.29, an exception tract is to be permitted to produce that proportion of its maximum daily potential that its surface acreage bears to the acreage in a standard spacing unit, as established by state-wide rule or special field order. Thus if 40-acre spacing has been ordered for a field, a 20-acre exception tract will be permitted to produce one-half of its maximum daily potential. This production allowance may be further reduced if the exception well is closer to boundary lines than the spacing order generally permits. In such case, even though the irregular tract may have the minimum required acreage, production is limited to that proportion of its maximum daily potential

³⁰ Section 1509.29.

³¹ *Ibid.* The proration formula prescribed for exception tracts is discussed in the next section of this article.

that the distance from the well to the boundary line of the exception tract bears to the standard distance established in the spacing order for regular tracts. Thus a spacing order might establish 40-acre spacing by prescribing 1320 feet between wells and 660 feet between the well and the boundary line, measured along the shortest line from the well to the boundary. Such an order would contemplate one well for every 40 acres, with the well located in the center of the drilling unit. Under this scheme, a well located on an irregularly shaped tract containing 40 acres but drilled only 330 feet measured perpendicularly from the boundary line would be allowed to produce only one-half of its maximum daily potential. Periodic tests of maximum daily potential are prescribed by the statute to keep the proration formula current.

Apart from promoting production from exception tracts to protect correlative rights, the statute forbids prorationing. The legislative purpose seems clear: demand for Ohio oil exceeds supply and the legislature wanted to capture as much of this market as possible. While national supply exceeds national demand, Ohio can capture the local market (or as much of it as Ohio production can supply) and thus reduce imports from other states. Any threat of price-cutting competition from other states is unrealistic, so the Ohio legislature might well have thought, since big producing states like Louisiana, Oklahoma and especially Texas cannot afford overproduction and falling prices. That this line of thinking was at least made known to the Ohio Legislature is demonstrated by the following excerpt from the Staff Research Report:

There are three sets of circumstances for which a state should establish proration based on economic considerations: either the transportation facilities are inadequate to move all of the produced oil, with the result that there is evaporation or other waste of stored oil; the market demand in the producing area of a state is such that prices for that state's oil will drop; or the state produces so much oil that the national price of oil will decline, thus affecting the state. The first two alternatives do not seem likely for Ohio as it presently produces only about 10 per cent of its domestic consumption, it is next door to sizable Eastern markets and steps are being taken to increase the transportation and refining outlets for Ohio oil. A comparable case is the neighboring state of Michigan which produced over three times the oil Ohio produced in 1961. It has a provision which allows a limitation of production to market demand, but it is never used because "demand exceeds production three to one."

It is also unlikely that Ohio will cause the national price of oil to decline. Ohio currently contributes less than two per cent of the national production, and any significant increase will be compen-

sated for on the national level by Texas acting in its role as the "national balance wheel" in oil economics. Texas can, and will, increase or curtail production in order to keep the price of oil at a reasonable level. Texas does not do this for any charitable purpose, but simply because it produces about 40 per cent of the national total and any change in price will affect Texas to a greater extent. Furthermore, Texas is farther away from markets than most other oil producing states, and when demand decreases, the other states' oil will displace Texas oil because of cheaper transportation costs. Texas can quickly increase production to meet a sudden demand for oil because it has the largest reserves in the country, and if it cuts back production during a market recession, the oil is still available for tomorrow.³²

Whatever views one may hold on market-demand limitations on production, one should recognize that the zeal of the legislature in banning such limitation in Ohio has led it to use language much broader than necessary—so broad in fact that effective conservation may be difficult to achieve for some reservoirs. One vitally important conservation tool is the establishment of gas-oil and water-oil ratios, whereby production in excess of the ratio is prohibited. By such regulations, primary reservoir energy is conserved and initial recovery greatly increased. Both the Armstrong Committee Report³³ and the Staff Research Report³⁴ recognized the desirability of granting authority to establish gas-oil ratios, and the draft bill contained a provision to this effect.³⁵ Recall, however, that section 1509.40, quoted above, forbids "limitation of production of oil or gas for any reason whatsoever."³⁶ Does this mean to deny the chief authority to limit production by regulating gas-oil and water-oil ratios? It will be remembered that the act nowhere expressly grants the chief rule-making power to prevent waste. True, waste is defined in the first section of the act³⁷ so as to include injury to the reservoir through dissipation of reservoir energy. The term "waste," however, makes but one other appearance in the act, *i.e.*, section 1509.20, in which operators are directed to "use every reasonable precaution in accordance with the most approved methods of operation to stop and prevent waste of oil or gas, or both." To find power in the chief

³² Staff Research Report 35-36.

³³ *Supra* note 29, at 5.

³⁴ *Supra* note 1, at 37.

³⁵ Section 1509.18 (last paragraph) of the draft version of the bill provided: "Upon his own motion or upon the application of any interested person, the chief of the division of oil and gas, after holding a hearing on the matter, may issue an order limiting gas-oil ratios for those wells that are determined to be producing at a wasteful gas-oil ratio."

³⁶ Section 1509.40. (Emphasis added.)

³⁷ Section 1509.01.

to set gas-oil and water-oil ratios to prevent waste of reservoir energy, one must determine that section 1509.20 imposes on operators the general duty to conserve reservoir energy, and that the chief can make particular rules and regulations under the power given him in section 1509.03. Obviously, it could be argued that the specific provision of section 1509.40 disallowing production limitations "for any reason whatsoever" overrides the general language of section 1509.20, so that production limitations based on gas-oil and water-oil ratios are forbidden by the act. Lack of general authority in the chief to issue rules to prevent waste lends strength to the argument as does deletion from the bill of express authority to regulate gas-oil ratios.

On the other hand, it seems unlikely that a new conservation statute establishing drilling controls, authorizing forced pooling and unitization, and reflecting a concern for maximizing ultimate recovery (through provisions for secondary recovery operations and in defining waste) would bar the conservation commission from instituting a fundamental production control designed to maintain reservoir pressure in the primary production stage. While the statute badly needs clarification, section 1509.40 can fairly be construed to prohibit production limitations based on market demand but not to prohibit limitations to prevent waste.

The argument to support this position would run along the following line: It is true that the legislature contemplated that regularly spaced wells would produce their maximum daily potential. This intention is reflected in section 1509.29, which limits irregularly spaced wells to a proportion of maximum daily potential, thus indicating the rate of production to be allowed regularly spaced wells. Notwithstanding this general declaration of policy regarding allowable production, the legislature made specific, contrary provisions with respect to production that entails waste. All operators are expressly enjoined to "use every reasonable precaution in accordance with the *most* approved methods of operation to stop and prevent waste of oil or gas, or both."³⁸ Waste is defined to include dissipation of reservoir energy as well as "producing . . . in a manner that reduces or tends to reduce the quantity of oil or gas ultimately recoverable under prudent and proper operations. . . ."³⁹ Since excessive gas-oil and water-oil ratios destroy primary reservoir energy thereby reducing ultimate recovery, their regulation is within the scope of the two sections. Viewing section 1509.40 in the context of the full act and seeking to reconcile all parts of the statute, section 1509.40 is intended only to forbid a state-wide proration scheme

³⁸ Section 1509.20 (Emphasis added.)

³⁹ Section 1509.01.

whereby total state production is curtailed below capacity and allowable production is allocated on a proportional basis to reservoirs and individual wells. It is not intended to prohibit customary measures to conserve reservoir energy, such as restrictions on gas-oil and water-oil ratios.

E. *Pooling*

(1) "Voluntary" pooling.

Section 1509.26 authorizes voluntary pooling by operators. Read literally, it may authorize pooling by lessees without the consent of their lessors. The statute provides: "The owners of adjoining tracts may agree to pool such tracts to form a drilling unit which conforms to the minimum acreage and distance requirements of the division" Section 1509.01(K) defines owner as "the person who has the right to drill on a tract or drilling unit and [the right] to drill into and produce from a pool and [the right] to appropriate the oil or gas that he produces therefrom either for himself or for others." For land under oil and gas lease, the owner is the lessee according to this definition. Thus it could be argued that the statute gives lessees the power to pool without the consent of their lessors (and other royalty owners) where the tracts to be pooled are (1) adjoining and (2) form a drilling unit in conformity to a state-wide or special field spacing order. Even if the statute is interpreted to force the pooling of royalty interests under these circumstances, lessees who wish to pool land to form units bigger than those established by agency order would have to obtain the consent of their lessors and, if Ohio follows the Texas rule,⁴⁰ of royalty and other owners of non-operating interests in the land.

It is quite possible, of course, that the statute will not be construed as we have suggested. An Ohio court might say that the section presupposes prior consent from the landowner. So construed, the section is wholly unnecessary, for it merely states a truism—that parties can make voluntary agreements. But such superfluity does not keep similar provisions out of the conservation statutes of other states.⁴¹

Construed to force pooling without lessor's consent, the statute presents no constitutional questions if applied prospectively, since

⁴⁰ *Brown v. Smith*, 141 Tex. 425, 174 S.W.2d 43 (1943). Louisiana follows the contrary rule. *LeBlanc v. Haynesville Mercantile Co.*, 230 La. 299, 88 So. 2d 377, 6 O. & G.R. 443 (1956). The subject is discussed and the Louisiana rule advocated in 6 *Williams & Meyers, Oil and Gas Law* § 925.1 (1964). See also 2 *Williams & Meyers, Oil and Gas Law* § 339.3, at 219-21 (1964).

⁴¹ *E.g.*, N.M. Stat. Ann. § 65-3-14(c) (1953); Okla. Stat. tit. 52, § 87.1(d) (1950); Pa. Stat. Ann. tit. 58, § 408(a) (1964).

it merely writes into leasing contracts, a clause deemed by the legislature, in the exercise of the police power to be for the general welfare. Applied retroactively, the statute presents more serious but not insuperable constitutional obstacles. As a matter of substantive law, the state can clearly prohibit drilling on tracts smaller than a prescribed size if the state allows the landowner to obtain his fair share of the petroleum recovered from a unit in which his land is placed.⁴² Moreover, a state can, and section 1509.27 of the Ohio statute does, provide for compulsory pooling of separately owned lands to form a single drilling unit. Section 1509.26 does no more than this, for it merely combines royalty interests when operators agree to pool their leases. Upon this reading of section 1509.26, section 1509.27 becomes a coordinate provision empowering the chief to pool both royalty and operating interests when the operators cannot agree on pooling. We see no difference in substance between mandatory pooling of royalty in the one case and in the other.

The remaining constitutional question is procedural. Must notice and a hearing be afforded the royalty owner? It should be noted that neither section 1509.26 nor section 1509.27 expressly provides for hearings for lessors. However, the only question in which the lessor has a legal interest in being heard after leasing is that of the formula for allocating production to the several tracts making up the drilling unit. Any requirement of a hearing on this issue is foreclosed under section 1509.27 by the statutory requirement that production be allocated on a surface acreage basis. No such provision appears in section 1509.26 and hence one could argue that, the allocation formula being variable, the statute must give the lessor an opportunity to be heard on the matter before his rights can be affected by government order. Thus the statute might be struck down or it might be construed (perhaps with some other provision of the Ohio statutes) to require a hearing. All of this is unnecessarily complex, we think, because production allocation in the case of both voluntary and compulsory pooling is almost invariably based on surface acreage. So long as this is the basis of allocation, we see no need for a hearing. Indeed, one might argue that, in the light of section 1509.27, section 1509.26 requires pro rata allocation according to surface acreage. If this view were adopted, the hearing problem is eliminated.

⁴² *Hunter v. Justice's Court*, 36 Cal. 2d 315, 223 P.2d 465 (1950); *Hunter Co. v. McHugh*, 202 La. 97, 11 So. 2d 495 (1942), *appeal dismissed*, 320 U.S. 222 (1943); *Superior Oil Co. v. Foote*, 214 Miss. 857, 59 So. 2d 85, 59 So. 2d 844, 1 O. & G.R. 735, 1 O. & G.R. 1239 (1952); *Brown v. Humble Oil & Ref. Co.*, 126 Tex. 296, 316, 83 S.W.2d 935, 87 S.W.2d 1069 (1935). See *Champlin Refinery Co. v. Corporation Comm'n*, 286 U.S. 210 (1932).

(2) Compulsory pooling.

Under the construction advanced above, section 1509.26 pools royalty interests when operators agree to pool working interests and section 1509.27 pools both royalty and workings interests when the operators cannot agree and one operator seeks and obtains a mandatory pooling order. If section 1509.26 does not pool royalty interests, then a recalcitrant royalty owner can be brought into the unit under the provisions of section 1509.27.

Prerequisite for making application for a mandatory order under section 1509.27 are two conditions, the existence of which, presumably, must be asserted in the application:

(1) The applicant has the operating rights on a tract that does not qualify for a well under the governing spacing order, whether it be the state-wide order or a special field order.

(2) The applicant has sought and failed to obtain voluntary pooling under the provisions of section 1509.26 "on a just and equitable basis." In practice this requirement probably means no more than that the applicant has made unsuccessful efforts to pool.

In addition, the application for a pooling order must be accompanied by an application for a drilling permit. Standing alone, this would seem to mean that in Ohio, unlike other states,⁴³ compulsory pooling must be sought *before* a well is drilled, not afterward. However, later provisions of the statute contradict this position. The next-to-last paragraph of section 1509.27 unambiguously contemplates pooling after completion of a well. Other provisions of the statute have a similar import.⁴⁴ In resolving the conflict, we suppose that the more explicit provisions control and that pooling after drilling is permitted.

The chief is required to notify "all owners of land within the area proposed to be included within the order" of filing of the application "and of their right to a hearing if requested."⁴⁵ As previously indicated, we construe this provision to extend only to those having operating rights on the land. Three reasons support this construction: (1) Owner is defined in section 1509.01(K) to include only those with operating rights and we believe the word "owners" in the phrase "all owners of land" is the same word

⁴³ *E.g.*, Louisiana, Mississippi, and Oklahoma. See 6 Williams & Meyers, Oil and Gas Law § 945 (1964).

⁴⁴ Another paragraph in section 1509.27 distinguishes between "cost of the drilling and operation, *or operation*, of a well . . . [and grants an election to become a non-participating owner in the] drilling and operation, *or operation*, of the well. . . ." (Emphasis added.) Distinguishing between "drilling and operation" and mere "operation" indicates that pooling may occur after a well is drilled, and at a time when the only costs to be accounted for are operation expenses.

⁴⁵ Section 1509.27 (second paragraph).

defined in section 1509.01(K). (2) Throughout the balance of the statute the word "owner" means operator; when the legislature meant to refer to others having interests in the land (as in the compulsory unitization section⁴⁶) it used the words "royalty owners."

(3) The substantive provisions of the order on which the hearing is held concern operators only. Those provisions cover the boundaries of the drilling unit, the drill site, the basis for sharing drilling and production costs, and the person to be designated operator of the unit. The only provision of legal concern to lessors is the one allocating production from the unit well. Since the statute fixes a invariable rule on allocation—pro rata sharing on the basis of surface acreage—participation in the hearing by royalty owners is pointless.

While we believe this interpretation is the preferable reading of the statute, we recognize that a court might read the word "owner" distributively, holding that "all owners of land" in section 1509.27 included lessors and royalty owners. In such a case, the same court is very likely to say that section 1509.26, which provides no notice to royalty owners, merely states the truism that if *all* parties agree there may be voluntary pooling. The reasoning would be that if the legislature provided for notice and hearing to royalty owners in compulsory pooling proceedings under section 1509.27, it surely would have done so in section 1509.26 if pooling of royalty interests thereunder had been intended to be compulsory. Since no hearing was provided for, no compulsory pooling was intended. And if the court should extend the right of notice and hearing to royalty owners in section 1509.27 as a matter of constitutional necessity, it seems most probable that section 1509.26, lacking provisions for notice and hearing, will be construed as merely declaratory of the existing law that lessees can pool if their lessors consent.

The two principal problems of compulsory pooling orders are dealt with expressly, though not clearly, in the act. The first problem is how costs are to be shared by operators owning leases in the drilling unit. An issue arises when an operator objects to putting up his share of drilling expenses for a well he expects to be noncommercial. At least four separate solutions to this problem are analytically possible: (1) The non-consenting operator could be required, despite his objection, to put up his share of the costs in cash in advance.⁴⁷ (2) The non-consenting operator could be given

⁴⁶ Section 1509.28(B).

⁴⁷ In *Superior Oil Co. v. Humble Oil & Ref. Co.*, 165 So. 2d 905, 21 O. & G.R. 58 (La. App. 1964), *writ refused*, 246 La. 842, 167 So. 2d 668, 21 O. & G.R. 66 (1964), it was held that a non-drilling lessee who had sought unitization could be compelled to reimburse the drilling lessee for a proportionate share of the drilling costs, rejecting the former's contention that he was entitled to be treated as a carried party. The case was noted in 39 Tul. L. Rev. 381 (1965).

a free ride, in that if the well were unsuccessful he would owe nothing, and if successful he would be liable for his share of costs out of production. This is the position taken by a number of states.⁴⁸ (3)

⁴⁸ Ala. Code tit. 26, § 179(36)C (1958) provides:

In the event such integration or pooling is required, the operator designated by the board to develop and operate the integrated or pooled unit shall have the right to charge against the interest of each other owner in the production from the wells drilled by such designated operator the actual expenditures required for such purpose, not in excess of what are reasonable, including a reasonable charge for supervision; and the operator shall have the right to receive the first production from such wells drilled by him thereon which otherwise would be delivered or paid to the other parties jointly interested in the drilling of the well so that the amount due by each of them for his share of the expense of drilling, equipping, and operating the well may be paid to the operator of the well out of production. . . .

Fla. Stat. Ann. § 377.28 (2) (1960) contains substantially the same provisions. It specifically states that an owner who objects to having his interests pooled shall not be liable for drilling costs in the event of a dry hole.

Ariz. Rev. Stat. Ann. § 27-505(A) (1956) gets the same result in fewer words: "As to owners who refuse to agree upon pooling, the order shall provide for reimbursement for costs chargeable to each such owner out of, and only out of, production from the unit belonging to such owner. . . ." Alaska Stat. § 31.05. 100(c) (1962); Colo. Rev. Stat. Ann. § 100-6-4(7) (1963); Neb. Rev. Stat. § 57-909(2) (1960); Nev. Rev. Stat. § 522.060 (1963); S.D. Code § 42.0706(3)(0)(6) (Supp. 1960); Utah Code Ann. § 40-6-6(g) (1960) contain substantially the same provision. The statutes of Alaska, Arizona, and Nevada give the unit operator a lien on the production allocated to the owners who object to having their interests pooled. This provision does not alter the free-ride nature of the statutes.

The Utah statute provides:

The order shall determine the interest of each owner in the unit, and may provide in substance that, as to each owner who agrees with the person or persons drilling and operating the well for the payment by the owner of his share of the costs, such owner, unless he has agreed otherwise, shall be entitled to receive, subject to royalty or similar obligations, the share of the production of the well applicable to the tract of the consenting owner, and, as to each owner who does not agree, he shall be entitled to receive from the person or persons drilling and operating the well on the unit his share of the production applicable to his interest, after the person or persons drilling and operating said well have recovered the share of the cost of drilling and operating applicable to such nonconsenting owner's interest plus a reasonable charge for supervision and storage.

The statutes of Colorado, Nebraska, and South Dakota contain substantially the same provision. The provision does not alter the free-ride nature of the statutes.

The provision of some statutes, of which Indiana's is typical, is somewhat ambiguous. Ind. Ann. Stat. § 46-1714(c) (1952) provides:

In the event such integration is required, the operator designated by the commission to develop and operate the integrated unit shall have the right to charge to each other interested owner the actual expenditures required for such purpose not in excess of what are reasonable, including charges for supervision, and the operator shall have the right to receive the first production from any well drilled by him thereon. . . .

The non-consenting owner could be relieved of any obligation to share in the risk of drilling, but if the well were successful he would be required to pay a sum greater than his share of costs, *e.g.*, 200 per cent of his share of costs. This is known as a non-consent penalty and is often used in voluntary pooling and unitization agreements⁴⁹ and in compulsory orders in some states.⁵⁰ (4) The non-consenting operator may be required to transfer his interest to the operator who wishes to drill, for a consideration fixed by the regulatory agency and based on the market value. This solution is adopted in a few states.⁵¹ In addition, the non-consenting operator can be given an election between the last two alternatives.⁵² The draft bill adopted the last-named solution,⁵³ but somewhere along the line, the mandatory transfer provision was deleted, so that the bill, as enacted, provides only for a 200 per cent non-consent penalty.

For the most part, the operation of the statutory non-consent provision is reasonably clear. An operator has a right not to participate in the risk of drilling; that is, an operator can insist on being a carried party,⁵⁴ although some of the terms and conditions of the carried arrangement can be determined by the chief. Such carried parties are designated nonparticipating owners in the statute; carrying parties are called participating owners. When an operator elects to be a carried party, production is divided as follows: the royalty interest of the lessor is deducted from production allocable to the non-consenting lessee's tract and is paid to the lessor. The

Ga. Code Ann. § 43-717(c) (1957); Ill. Ann. Stat. ch. 104 § 83a(b) (Smith-Hurd Supp. 1964); N.C. Gen. Stat. § 113-393(a) (1960) are very similar. These statutes will probably be construed to give the non-consenting operator a free ride.

⁴⁹ See 6 Williams & Meyers, Oil and Gas Law § 921.10 (1964).

⁵⁰ *Id.* § 944. See also Note, 39 Tul. L. Rev. 381, 383 (1965).

⁵¹ *E.g.*, Ark. Stat. Ann. § 53-115 3-1(C)(d) (Supp. 1963); Okla. Stat. tit. 52, § 87.1(d) (1961) (discussed *infra*, note 57).

⁵² *Ibid.*

⁵³ Section 1509.24 of the draft bill provided:

If the owner does not elect to participate in the risk and cost of the drilling and operation, or operation, of a well, the order shall further provide for one or more just and equitable alternatives whereby such owner may either elect to surrender his leasehold interest to the participating owners on some reasonable basis and for a reasonable consideration which, if not agreed upon, shall be determined by the chief; or he may elect to be a nonparticipating owner in the drilling and operation, or operation, of the well, on a limited or carried basis upon terms and conditions determined by the chief to be just and reasonable.

The section went on to require a 200% nonconsent penalty.

⁵⁴ A carried party is an owner of minerals for whom costs are advanced by the carrying party, who recovers such costs out of production attributed to the carried party's interest. See Williams & Meyers, Manual of Oil and Gas Terms 42 (1964) (under the entry, "Carried interest").

balance of the production allocable to the tract is paid to those who bore the well expense until they have recouped twice the share of costs allocated to the tract.⁵⁵ As an example, suppose the following case. A unit well produces 5000 barrels of oil a month from a unit consisting of 50 acres. *O* is the non-consenting lessee of 10 acres. Under the statute his tract is entitled to 1000 barrels for that month, since his surface acreage is one-fifth of the total unit acreage. Assume that the lease with the fee owner calls for the usual one-eighth royalty. The fee owner would get 125 barrels of oil; the remaining 875 barrels would be credited against the obligation of the non-consenting operator. This process would continue monthly until the value of the oil credited to *O*'s account equalled 200 per cent of his share of drilling expense. Thereafter, for the first time, *O* would receive income from the well, measured by his share of the working interest oil (the 875 barrels mentioned above) less his share of operating costs. The statute apparently permits the penalty to apply to operating costs indefinitely, so that the non-consenting operator will be paying twice his share of operating costs for as long as production lasts, if the mandatory pooling order so provides. In the rare case of unleased land, the fee owner of the minerals is treated as if he had leased, receiving one-eighth of the attributed production free of costs, with the remaining production going to satisfy 200 per cent of the landowner's share of drilling costs.

The act does not make explicit provision for excess royalty reserved by a lessor, but the general statutory provisions seem to require that the royalty reserved by a lessor, whatever its size, be deducted from the non-consenting operator's share of production and paid to the lessor before any share of production is allocated to satisfy the claim of the carrying party. Thus, if the lease on Blackacre reserves a one-fourth royalty and the lessee elects to be carried, the claim of the carrying party must be satisfied out of three-fourths (rather than seven-eighths) of the production allocated to Blackacre.

The same allocation of production would be made where land is burdened by an outstanding nonparticipating royalty interest and is leased by the executive for an excess royalty. Thus if *X* owns a perpetual, nonparticipating $\frac{1}{16}$ royalty in Blackacre and *L*, the owner of Blackacre, leases the land for $\frac{3}{16}$ royalty, $\frac{1}{16}$ being designated as *X*'s and $\frac{2}{16}$ as *L*'s, the carrying party's claim must be satisfied out of $\frac{13}{16}$ of the production allocated to Blackacre.

The situation is less clear where Blackacre has not been leased by *L* and is subject to an outstanding $\frac{1}{16}$ nonparticipating royalty interest owned by *X*. The statute provides that the carrying party

⁵⁵ Section 1509.27.

shall be entitled to Blackacre's share of production "exclusive of the royalty interest if the fee holder has leased his land, otherwise one-eighth of his share of the production. . . ." We believe the statute would be construed to allocate a $\frac{1}{8}$ royalty to Blackacre and to leave to the agreement of the parties the division of royalty. Thus *X* would take one-half of the royalty and *L* would take the other half.

In the unlikely event of a landowner granting a nonparticipating royalty in excess of $\frac{1}{8}$, a flat application of the statutory words would limit the royalty owner's share of production to the statutory $\frac{1}{8}$. At first blush this result seems inconsistent with allowing excess royalty where the land has been leased. Further reflection convinces us that the result is sound. A legislature might well decide not to allow a landowner to create excess royalty and reap the economic benefit therefrom and yet decline to participate in the costs of drilling, which might never be recovered because of the large outstanding royalty. The legislature might well distinguish this situation, which is wide open to abuse, from the case of excess royalty obtained by a landowner in arms' length bargaining with an oil and gas lessee. The self-interest of the lessee, whose return depends upon the lease having value in excess of the royalty, could be thought a sufficient safeguard against the improper use of excess royalty.

The division of costs between participating and nonparticipating operators is determined by the chief according to a standard of "just and reasonable."⁵⁶ The chief also has the power to determine the amount of the costs, in case of dispute. We would expect the usual allocation of costs to be based on surface acreage, since production is allocated on this basis.

Two questions are raised by the non-consent penalty provision in the act. The first is its constitutional validity and the second, which bears closely on the first, is the discretion the chief has in applying it.

Several states have non-consent penalty provisions in their compulsory pooling and unitization statutes, but these are usually coupled with an option given the non-consenting operator either to pay the penalty out of production or to sell his lease to the unit operator.⁵⁷ However, at least one other state (New Mexico) makes

⁵⁶ Section 1509.27 (third paragraph).

⁵⁷ *E.g.*, Pa. Stat. Ann. tit. 58, § 408(c) (1964). See Ky. Rev. Stat. § 353.640(3) (Baldwin 1963).

Okla. Stat. tit. 52, § 87.1(d) (1961) does not specify the modes of adjusting the rights of consenting and non-consenting operators with regard to expenses, but the Oklahoma commission, under the authority of this section has required the payment in advance of a non-consenting operator's share of expenses or his sale of the lease to

the non-consent penalty the only alternative to sharing the risk.⁵⁸

The validity of orders requiring the non-consenting operator to transfer his lease for a consideration set by the agency or to share in the risk of drilling by putting up his part of costs (or a bond therefor) has been established in one state court and has passed muster in the United States Supreme Court.⁵⁹ We know of no case sustaining a non-consent penalty either as the non-consenting operator's sole option or as an alternative to selling his lease.⁶⁰ Can it pass the constitutional test? So far as the United States Supreme Court is concerned, we think the practical answer is yes, whatever constitutional objections might be thought to exist in theory. The Court has not invalidated, on constitutional grounds, a state oil and gas conservation statute or order since 1937,⁶¹ and it has in full opinions⁶² and by *per curiam* orders⁶³ upheld a good many.

The practical test on constitutionality will therefore come in the Ohio Supreme Court. We have neither the learning nor the desire to acquire the learning necessary to predict the Ohio court's conclusion on the question, since its decision will presumably rest (at least in part) on its prior substantive due process decisions. We can, however, seek to identify the issues that will be presented and develop some of the considerations relevant to the decision.

the unit operator. Such orders have been upheld. *Anderson v. Corporation Comm'n*, 327 P.2d 699, 7 O. & G.R. 72, 9 O. & G.R. 196 (Okla. 1957), *appeal dismissed for want of a substantial federal question*, 358 U.S. 642 (1959); *Wakefield v. Oklahoma*, 306 P.2d 305, 7 O. & G.R. 291 (Okla. 1957). A leading authority on the subject states that the Oklahoma commission has also ordered the non-consenting owner to elect between selling his lease and becoming a carried party subject to a non-consent penalty. Myers, *The Law of Pooling and Unitization* 238 (1957) (stating that the non-consent penalty is 150 to 200% of costs).

⁵⁸ N.M. Stat. Ann. § 65-3-14(c) (Supp. 1965) (50% limitation on the penalty).

⁵⁹ *Anderson v. Corporation Comm'n*, *supra* note 57.

⁶⁰ The case nearest in point is *Wakefield v. Oklahoma*, *supra* note 57, in which the court rejected the non-consenting party's contention that in addition to the option to pay a share of expenses or sell the lease the non-consenting owner must be afforded the option to become a carried party with a non-consent penalty of 150% of his proportionate share of costs. Such a decision does not come close to holding that non-consent penalties are valid.

⁶¹ *Thompson v. Consolidated Gas Util. Corp.*, 300 U.S. 55 (1937).

⁶² See, e.g., *Cities Serv. Gas Co. v. Peerless Oil & Gas Co.*, 340 U.S. 179 (1950) (minimum gas price statute); *Railroad Comm'n v. Rowan & Nichols Oil Co.*, 311 U.S. 570 (1941) (prorationing scheme in East Texas field).

⁶³ *Anderson v. Corporation Comm'n*, 358 U.S. 642 (1959) (compulsory pooling order requiring lessee to pay his share of costs of unit well in advance or sell his lease to unit operator); *Humbel Oil & Ref. Co. v. Railroad Comm'n*, 331 U.S. 791 (1947) (proration order causing petitioner to suffer drainage of 30 million barrels of oil); *Hunter Co. v. McHugh*, 320 U.S. 222 (1943) (compulsory pooling statute).

The following underlying propositions should be beyond dispute: the objectives of compulsory pooling are well within the police powers of the state. These objectives are to prevent economic waste resulting from the drilling of unnecessary wells and to protect correlative rights by enabling mineral owners to receive out of production their proportionate share of the minerals in place. If anyone doubts the social benefit of compulsory pooling, let him examine the sorry mess existing in Texas from the 1930's until this year, when a pooling statute was finally enacted.⁶⁴ When tracts are combined through compulsory pooling, the problem must be faced of the operator owning a lease in the unit who objects to the financial risk of drilling. As we have seen, some states, by statute or commission policy, place the full risk of a dry hole on the operator who wishes to drill.⁶⁵ While this may be reasonable, it is certainly not unreasonable to put some limits on free rides. The question is: What sort of limits? Here the matter of discretionary application of the penalty becomes important. As we read the statute, the sole alternative to participation in costs is the imposition of the penalty, always in the amount of 200 per cent—no more, no less. It is true that section 1509.27 permits a nonparticipating owner to elect to become a carried party "upon terms and conditions determined by the chief to be just and reasonable." But the following sentence takes away the discretion conferred by this provision, for it provides that the participating owners "shall be entitled" to the 200 per cent non-consent penalty.

We confess to a lack of enthusiasm for a rule that says, in every case, without regard to the degree of risk, the price of refusal to share in drilling costs at the outset is 200 per cent of those costs if the well comes in. The statutes of other states are not so rigid; even New Mexico limits the penalty to a maximum of 150 per cent of costs and allows the commission to vary the figure downward depending on the risk involved.⁶⁶ In fact, a penalty of an additional 25 per cent of costs is the common New Mexico practice.⁶⁷ Since the aim of the non-consent penalty is to compensate the participating lessees for the risk they have taken, an inflexible penalty of 200 per cent of costs begins to look somewhat arbitrary.

One test of its constitutional validity might be the following: Is there another practicable means of obtaining the same result

⁶⁴ See Hardwicke, "Oil Well Spacing Regulations and Protection of Property Rights in Texas," 31 Texas L. Rev. 99 (1952); Hardwicke & Woodward, "Fair Share and the Small Tract in Texas," 41 Texas L. Rev. 75 (1962).

⁶⁵ See note 48 *supra*.

⁶⁶ N.M. Stat. Ann. § 65-3-14 (Supp. 1965).

⁶⁷ 6 Williams & Meyers, Oil and Gas Law § 905.2 (1964).

but better calculated to protect the interests of the parties? The answer to this question depends on the ability to make a nice determination of the risk of drilling. We believe that in many instances, a closer calculation may be made. The probabilities of commercial production are a great deal higher with development wells than with outpost wells drilled in hopes of making a long extension of a partly developed pool. On the other hand, in any particular case, there could be violent disagreement between two equally positive experts over the classification of the well as a development well or an outpost well. It would have been better, in our view, to give the chief discretion to make the penalty less than 200 per cent, as it would have been better to afford the non-participating owner a three-way option: (1) to pay, (2) to assign the lease for a consideration, or (3) to suffer a non-consent penalty. Nevertheless, we would not conclude that the statute is unconstitutional for failure to do so. A legislature could rationally reach the conclusion that requiring the regulatory commission to determine the risk of drilling in every case of dispute was unduly burdensome, since the accuracy of the determination would always be doubtful and the expense of administration much greater. While the judges—and we—might disagree with this conclusion, a reasonable man could adopt it, and hence the provision should be upheld.

A final question, one of interpretation, should be raised about the statutory sharing arrangements between consenting and non-consenting operators. The next-to-last paragraph of section 1509.27 provides:

In instances where a well is completed prior to the pooling of interests in a drilling unit under this section, the sharing of production and *adjustment of the original costs* of drilling, equipping, and completing the well shall be from the effective date of the mandatory pooling order.⁶⁸

This section is designed, of course, to deal with the sharing of income and expense of a well drilled before the unit is formed. There is no occasion for the imposition of a non-consent penalty, because the operator who drilled, willingly took the risk before he or anyone else proposed the formation of a unit. The two questions under the section are: (1) How are pre-pooling capital and operating expenses to be accounted for, and (2) how is pre-pooling production income to be divided? While the language of the paragraph is somewhat uncertain in meaning, particularly the reference

⁶⁸ Section 1509.27. (Emphasis added.)

to "adjustment of the original costs," we believe that the intent was to divide unrecovered drilling expense and production income thereafter accruing, as of the effective date of the pooling order. To illustrate the operation of the paragraph as thus construed, suppose operator *O* drilled a well on a twenty-acre leasehold. Thereafter forty-acre spacing is ordered for the field, and *O*'s lease is pooled with operator *P*'s adjoining, undrilled, twenty-acre leasehold. At the time this mandatory pooling order took effect, *O* had produced 100,000 dollars of working interest oil, thereby recovering one-half of his original drilling and equipment costs of 200,000 dollars. (Operating expenses will be ignored for simplicity.) On our proposed reading of the statute, *P* would be entitled to one-half of the oil thereafter produced by the well (less the royalty he owes his lessor) and would be liable to pay out of such production 50,000 dollars in capital costs.

Adjusting the benefits and burdens as of the date of pooling awards an appropriate benefit to the drilling operator where he has fully recovered his costs and is making a profit when pooling is ordered. Thus, using the parties above, if *O* has recovered the full 200,000 dollars in capital costs and has a profit of 100,000 dollars from production when the pooling order takes effect, *P* gets no share of the past profit. His participation in production income begins on the effective date of pooling. Since *O* alone has taken the risk of drilling, he is entitled to receive the profit made before pooling.

The statute may be read, less plausibly we think, to direct the reconstruction of the income and expense accounts retroactively to the commencement of drilling. *P* would share in half the income and pay half the expenses from such time. In the second example given above, he would thus obtain one-half of the 100,000 dollars profit that accrued before pooling. Despite the reference to an adjustment of the *original* costs of drilling, equipping and completing the well, we doubt that the legislature intended to adopt this procedure. It is clear that the income account is not reconstructed for the benefit of royalty owners, for the statute explicitly states that "the sharing of production . . . shall be from the effective date of the mandatory pooling order." This is a practical provision to avoid the need and difficulty of recovering one-half of the royalty payments made to *O*'s lessor and handing them over to *P*'s lessor. If we are to handle production income the same for both lessor and lessee (and we should because the statute makes no distinction between them for this purpose), we cannot reconstruct the income account for the purpose of allowing the late-joining operator to share in previous profits.

A third constructional possibility is to charge the late-joining operator's share of original costs to production obtained after entry of the pooling order. We can see no reason, however, why the legislature would wish to charge a share of original costs without crediting initial production. Moreover the statute directs that the adjustment of original costs be made as of the effective date of the pooling order, which seems to require that credit be given for costs recouped before pooling.

In sum, it is our view that the present statutory language was intended to have the same effect as the language in the proposed bill,⁶⁹ which was probably taken from the Pennsylvania act:

In instances where a well is completed prior to the integration of interests in a drilling unit, the sharing of production shall be from the effective date of the integration, except that, in calculating costs, credit shall be given for the value of the owner's share of any prior production from the well.⁷⁰

The other principal problem that must be solved in any compulsory pooling statute is the effect of the mandatory order on lease terms. Because the same problem is also presented by compulsory unitization orders, we shall postpone discussion of it until we have considered the unitization section of the act.

F. *Compulsory unitization*

In addition to compulsory pooling, the act provides for compulsory unitization. The differences between the two go both to size and purpose: compulsory pooling is designed to save drilling costs and to protect correlative rights by putting together enough land to form a drilling unit, which might be 40 to 80 acres for oil wells and as much as 640 acres for gas wells. Each field is divided up into uniform drilling units, with one well on each unit in the pool. Compulsory unitization is designed to place all or a substantial part of a reservoir under the management of one operator, with wells quite irregularly spaced if reservoir mechanics make this desirable. Other purposes of unitization generally (though not necessarily in Ohio) are to reduce (even more than the spacing order does) the number of wells drilled into the pool, to permit pressure maintenance and cycling operations, and to carry on secondary recovery operations.⁷¹

(1) Requisites for obtaining an order.

Under section 1509.28, compulsory unitization may be initiated by either the chief or by operators owning leases on 65 per cent of

⁶⁹ Section 1509.24 of the draft bill (next-to-last paragraph).

⁷⁰ Pa. Stat. Ann. tit. 58, § 408(c) (1964) (last sentence).

⁷¹ See 6 Williams & Meyers, Oil and Gas Law §§ 901, 913.1 (1964).

the land overlying the pool. For an order compelling unitization to take effect the following conditions must be met:

(1) The chief must find that unitization is "reasonably necessary to increase substantially the ultimate recovery of oil and gas" from the pool. (Although the statutory use of the words "oil and gas" is in the conjunctive, the legislative intent was undoubtedly to speak in the disjunctive, for it makes no sense to limit unitization to pools producing both kinds of hydrocarbons. Moreover, elsewhere in the statute, provisions relating to compulsory unitization speak of oil and gas in the disjunctive. It would seem, however, that the requirement that the chief find that ultimate recovery will be increased limits the purposes for which unitization may be ordered. For example, if the sole purpose and effect of the order is to save drilling expense, the order is probably not authorized.)

(2) The chief must find that the value of the estimated additional recovery will exceed the cost of conducting the unit operation.

(3) The unit operation plan, prescribed in the order, must be approved in writing by operators who will be required under the plan to pay 65 per cent of the costs of the operation. Quite conceivably, this could be a single operator.⁷²

(4) The unit operation plan must be approved in writing by owners of 65 per cent of the royalty in the unit.

The exact language of this last condition requires approval "by the royalty owners of sixty-five per cent of the normal one-eighth royalty in the unit." "Royalty interest" is defined in section 1509.01(L) to mean "the fee holder's interest in the production from a well, usually one-eighth of the gross production." The statute apparently intends, therefore, not to extend the vote to owners of overriding royalty, oil payments, or other nonoperating interests carved out of the working interest. Other statutes provide for a broader franchise,⁷³ but such extension of the right to vote is apparently unnecessary under the federal constitution. As first enacted the Oklahoma unitization statute allowed the vote to operators but not to lessor-royalty owners and was upheld in these words by the Oklahoma Supreme Court:

The question is not the wisdom of granting the right of protest to the lessees while withholding it from the royalty owners but whether it was within the power of the Legislature so to do. It was

⁷² Some statutes require the consent of at least two operators. See 6 Williams & Meyers, *Oil and Gas Law* § 913.5 (1964).

⁷³ *E.g.*, Mich. Stat. Ann. § 13.139 (107) (Supp. 1963) (vote on plan given to "those persons who are owners of record of at least 75 per cent of the production or proceeds thereof that will be credited to interests which are free of cost such as but not limited to royalties, overriding royalties and production payments . . .").

within the power of the Legislature to do so because being within its police power to enact the law without the consent of either lessees or royalty owners it was optional with it to require the consent of either. Where privilege is granted to some in such situation the Constitution is satisfied if all similarly situated are treated alike.⁷⁴

The United States Supreme Court dismissed the appeal.⁷⁵

It might be argued that granting the right to vote to some royalty owners but not to others is an unreasonable classification and hence a violation of the equal protection clause, but a convincing answer seems to be that adequate protection is otherwise given to overriding royalty owners. The interest of the lessee and of the overriding royalty owner will often be identical, for the production allocated to the tract will be shared by both. The vote given to the operator is sufficient protection of the overriding royalty owner's interest in such a case. Moreover the plan is subject to attack by the overriding royalty owner where he believes he has suffered from unfair dealing by the operator.⁷⁶ Such a case might arise where an operator owned adjoining leases within the unit area and contrived to have more unit production allocated to the lease not burdened by overriding royalty than to the lease subject to complainant's interest. Protection against unfair dealing of this kind will be afforded the overriding royalty owner whether or not he was entitled to vote, or did vote, on the plan.⁷⁷ We believe, therefore, that the lack of voting rights in overriding royalty owners does not invalidate the statutory scheme for imposing unitization on a pool.

A second question raised by the voting provisions is how the tally is made of royalty owner's votes. The statute requires written approval "by royalty owners of sixty-five per cent of the normal one-eighth royalty in the unit." Two uncertainties inhere in this language: (1) What are the voting rights of owners of royalty larger or smaller than "the normal one-eighth"? (2) What weight, if any, is to be given to acreage?

Regarding the first question, several constructional possibilities exist. Read literally, the statute could mean that owners of abnormal (or subnormal) royalty cannot vote at all. The only voters are

⁷⁴ *Palmer Oil Corp. v. Phillips Petroleum Co.*, 204 Okla. 543, 549, 231 P.2d 997, 1004 (1951).

⁷⁵ *Palmer Oil Corp. v. Amerada Petroleum Corp.*, 343 U.S. 390 (1952).

⁷⁶ Section 1509.36 permits "any person claiming to be aggrieved or adversely affected by an order of the chief" to appeal to the Oil and Gas Board of Review, whence a further appeal can be taken to the courts. Section 1509.37. Moreover, review of the unitization order may be sought in the first instance in the courts. Section 1509.36.

⁷⁷ See 4 Williams, *Oil and Gas Law* § 670.2 (1962).

"royalty owners . . . of the normal one-eighth . . ." Since no reason whatever can be discovered for taking the vote away from owners of excess or undersized royalty, and since to do so might raise very serious questions of equal protection, we reject such a construction.

Another possibility is to construe the statute as providing a one-man-one-vote rule, whereby owners of more or less than one-eighth royalty are given the same voting power as owners of the usual royalty. Literal application of such an interpretation would be absurd, however, because the owner of a standard one-eighth could subdivide his royalty into as many parts as would be necessary to defeat the plan. We doubt that even extreme advocates of the one-man-one-vote principle would go so far.⁷⁸

A third constructional possibility is to read the statute as treating all royalty as being, for voting purposes, one-eighth of production per tract of land. Owners of excess royalty would be treated as owning only one-eighth; owners of subdivided royalty (whether created before or after lease) would be given partial votes in the proportion that their fractional interest bears to the standard one-eighth. Under this interpretation, a landowner who leased for one-sixteenth instead of the usual one-eighth might or might not get a whole vote. We doubt that the legislature gave any thought at all to this problem; while royalty in excess of one-eighth is common enough to command attention, lease royalty of less than one-eighth is exceedingly rare if, in fact, it ever occurs. The operation of the statute, upon this construction, can be illustrated by an assumed and highly simplified set of facts: *A*, *B*, and *C* each own 1000 acres of land in fee, the total of which makes up the entire unit area. *A* leased for a $\frac{1}{4}$ royalty; *B* for the standard $\frac{1}{8}$; and *C* for the standard $\frac{1}{8}$, but *C* conveyed one-half of his royalty to *D*. *A* has one vote; *B* has one vote; and *C* and *D* each have one-half of a vote. Any combination of three affirmative votes out of this group will satisfy the statute since *A* owns only $\frac{1}{8}$ royalty for voting purposes. Moreover, affirmative votes by *A* and *B* will be sufficient approval of the plan although *C* and *D* dissent, since *A* and *B* together have, for voting purposes, two-thirds of the total fee owner's royalty in the unit area.

A fourth constructional possibility views the statute as reflecting only one legislative concern; that of subdivided landowner royalty. The legislature could very properly be concerned that owners of less than one-eighth be limited in their voting power. As we have pointed out, one royalty owner opposed to the unit

⁷⁸ *But cf.* Warren, C. J.: "Again, people, not land or trees or pastures, vote." *Reynolds v. Sims*, 377 U.S. 533, 580 (1964). We continue to believe that royalty, while classified as land for most purposes, is not land for this purpose.

operations plan could defeat the plan by royalty conveyances if every owner of royalty of whatever size has one vote. And while a legislature might consider this possibility too unlikely an event to provide for, the division of land-owner royalty both before and after lease is an exceedingly common occurrence. A legislature could thus be concerned with providing a system whereby voting weight was in accordance with economic interest. This is precisely the standard used with respect to operators, who vote in accordance with their share of unit operation expense. Thus, the legislature took the normal one-eighth royalty as the voting standard, intending to decrease voting strength for owners of less and to increase it for owners of more, with the weight of the vote depending on the ratio between the owners' royalty and the normal one-eighth royalty. In the example given, *A* would have two votes, *B* one vote, and *C* and *D* one-half vote each. *A* alone could block the unit plan. *A* and *B*, having together 75 per cent of the votes, could put the plan into effect, as could *A*, *C*, and *D*. For reasons that will be given in the following discussion of the weight to be given to acreage we believe the legislature intended the result last suggested, which we also believe to be the preferable voting scheme.

The statute fails to indicate clearly the weight that acreage is to have in the royalty owners' vote. Disregarding language relating to the problem discussed in the preceding paragraphs, the statute requires written approval "by the royalty owners of sixty-five per cent of the . . . royalty in the unit." We believe the intent here was to put voting on a royalty-acre basis.⁷⁹ It seems unlikely that the cumbersome phrase quoted above was intended to adopt the one-man (*i.e.*, one royalty owner)-one-vote principle, for the natural phrase to accomplish this purpose is to require approval by "sixty-five percent of the royalty owners in the unit." The phrase actually used parallels the provision on operator voting, where there must be an affirmative vote "by those owners who . . . will be required to pay at least sixty-five percent of the costs of the unit operation" If expenses are allocated on the basis of surface acreage, value of leaseholds, acre-feet of recoverable oil or gas in place, or on any other basis reflecting the economic interest of the operator, as we think the federal and state constitutions are likely to require, then the argument is persuasive that royalty

⁷⁹ Williams & Meyers, *Manual of Oil and Gas Terms* 344 (1964), defines "royalty acre" as follows: "A full one-eighth royalty on one acre of land; *e.g.*, in a one-hundred acre tract, ownership of one-half of the royalty interest (where a minimum one-eighth is required in leases) or of a $\frac{1}{16}$ royalty is the equivalent of owning 50 royalty acres. See *Dickens v. Tisdale*, 204 Ark. 838, 164 S.W.2d 990 (1942); *Inslee v. Palmer*, 153 Kan. 147, 109 P.2d 208 (1941)."

voting rights were intended to be established on the same basis—economic interest of the royalty owner. We therefore believe that the phrase “royalty in the unit” means the number of royalty acres in the unit and that the statute requires an affirmative vote of owners of sixty-five per cent of the total number of royalty acres, one royalty acre being “the normal one-eighth royalty” on one acre.

The operation of the voting section upon this construction of the statute is demonstrated in the following illustration. Suppose in a 640-acre section the division of ownership and the lease royalty are as follows:

<u>Land-owner</u>	<u>Premises owned</u>	<u>Lease royalty</u>
<i>A</i>	N.W. $\frac{1}{4}$	$\frac{1}{4}$
<i>B</i>	N.E. $\frac{1}{4}$	$\frac{1}{8}$
<i>C</i>	Undivided $\frac{1}{2}$ of south $\frac{1}{2}$	$\frac{1}{8}$ (of which <i>C</i> gets $\frac{1}{2}$ or a $\frac{1}{16}$ royalty)
<i>D</i>	Undivided $\frac{1}{2}$ of S.W. $\frac{1}{4}$	$\frac{1}{8}$ (of which <i>D</i> gets $\frac{1}{2}$ or a $\frac{1}{16}$ royalty)
<i>E</i>	$\frac{1}{32}$ nonparticipating royalty in S.E. $\frac{1}{4}$	$\frac{1}{8}$ (of which <i>E</i> gets $\frac{1}{4}$)
<i>F</i>	Undivided $\frac{1}{2}$ of S.E. $\frac{1}{4}$, subject to <i>E</i> 's $\frac{1}{32}$ royalty interest	$\frac{1}{8}$ (of which <i>F</i> gets $\frac{1}{4}$)

In this situation the royalty acres owned and the voting rights are as follows:

<u>Land-owner</u>	<u>Royalty acres</u>	<u>Votes</u>
<i>A</i>	320	320
<i>B</i>	160	160
<i>C</i>	160	160
<i>D</i>	80	80
<i>E</i>	40	40
<i>F</i>	40	40
Total	800	800

Ordinarily, if the lease royalty is uniformly $\frac{1}{8}$ on all portions of the section of land proposed to be unitized, there would be 640 royalty acres, and 640 votes. The required 65 per cent vote would mean that there must be 416 affirmative votes. In this hypothetical, by reason of the abnormal royalty in *A*'s lease, there will be 800 royalty acres in the section and 800 votes; *A*'s $\frac{1}{4}$ royalty has added 160 votes to the rolls. The required 65 per cent means there must be 520 affirmative votes.

This last suggested voting scheme is the one we think the legislature most likely intended: It parallels the voting system established for operators, it gives rational effect to the phrase "normal one-eighth" and it explains the use of the cumbersome phrase "owners of sixty-five per cent of . . . royalty in the unit" when "sixty-five per cent of royalty owners" would have been the natural phrase if acreage were intended not to be a factor in the voting process. Moreover, we believe that since the legislature gave royalty owners a vote, when it did not have to,⁸⁰ it is more likely than not that the vote was intended to be weighted in accordance with the economic interest of the voter. There is little point in giving royalty owners a vote at all if all votes count equally, regardless of financial interest. Indeed, large landowners with the biggest financial interest might prefer no vote for royalty owners at all over a voting system that disregards acreage, for they might be better off if the operators (with whom the large landowners have a community of interest) and the chief alone determined the contents of the plan. To the extent, then, that the voting provisions reflect legislative concern over royalty owners' economic interests, the statute should be construed to fix voting on a royalty acre basis.

(2) Contents of the order.

Having concluded our consideration of the conditions prerequisite to the effective promulgation of a unitization order, we turn now to the contents of the order. The standard governing the chief in fixing the terms and conditions of the order is that of "just and reasonable," which is vague, but perhaps necessarily so. At any rate, it is commonplace in unitization statutes.⁸¹ The order is to prescribe a plan for unit operations which shall specify the boundaries of the unit area, the nature of the operations contemplated, the formula for allocating production to the tracts in the unit, the credits and charges to be made for equipment contributed to the unit operation, the formula for sharing expenses, the mode of supervising the operation, and the time the unit operation shall begin and end. Provision is made for additional terms in the order as may be appropriate for conducting the operation and protecting correlative rights. Most of these provisions are routine; only a few need to be noticed specially.

⁸⁰ *Palmer Oil Corp. v. Phillips Petroleum Co.*, 204 Okla. 543, 231 P.2d 997 (1951), *appeal dismissed*, 343 U.S. 390 (1952), discussed at text accompanying notes 74 & 75 *supra*.

⁸¹ See, e.g., Ala. Code tit. 26, § 179(72) (1958) ("order shall be fair and reasonable and equitable"); Mich. Stat. Ann. § 13.139 (106) (Supp. 1963) ("fair, reasonable and equitable"); Okla. Stat. Ann. tit. 52, § 287.4 (Supp. 1964) ("fair, reasonable and equitable").

The formulation and promulgation of a unitization order must be preceded by a hearing in which the parties will present evidence on the need for unitization and the essential terms of the order. The two provisions of primary importance in any order are the production allocation formula and the expense-bearing formula. The statute specifies the basis for sharing production in the absence of agreement by the interested parties, which we take to include royalty owners. The statutory standard is "value . . . for development of oil and gas by unit operations," with each tract sharing production in the ratio that its value (so defined) bears to the total value of the tracts in the unit. The determination is made by the chief on the evidence adduced at the hearing.

No standard for sharing expenses is specified in the act. We should think, however, that the expense-bearing formula would usually conform to the production participation formula, for an operator's return should ordinarily be commensurate with his investment.

Unlike the pooling section, the unitization section grants no election to an operator to participate in expenses or to become a carried party subject to a non-consent penalty. The statute provides that an order should include:

(6) A provision, if necessary, for carrying or otherwise financing any person who is unable to meet his financial obligations in connection with the unit, allowing a reasonable interest charge for such service;⁸²

The intent here seems to be to require all operators owning leases in the unit to bear their share of expenses if financially able to do so. An operator (or the owner of unleased lands) who lacks the financial ability to participate is to be carried or otherwise financed and charged a fee for this service. The statute does not contemplate orders requiring a non-consenting operator to pay or to sell his interest, nor does it adopt the flat 200 per cent non-consent penalty of the pooling statute. Why does the unitization section differ in this way from the pooling section and can such difference be justified? We believe the difference exists because of and is justified by the difference in theory between the two sections. The pooling section anticipates that risks will be taken in the boring of wells on the pooled drilling unit. It permits an operator to opt out of the risk by paying out of production, if any, twice his share of costs.

⁸² Section 1509.28(A) (6).

The unitization section contemplates a low-risk operation. This is not to say that all wells will be successful or that the operation will be profitable from the beginning. But the statute does assume a producing reservoir that can be made more profitable—in the long run—by unit operations engaged in pressure maintenance or secondary recovery. Before unitization can be ordered, the chief must find that unit operation will substantially increase the ultimate recovery of petroleum and that the estimated value of the increased recovery will exceed the estimated costs of the operation. Of course the chief may be wrong, but on such findings, it is nonetheless reasonable to make operators who can pay their share of costs without a right of refusal, and to allow operators who cannot pay to remain in the operation subject to a financing charge.

Apart from the effect of unitization orders on lease terms, the remaining provisions of the unitization statute deserve only brief notice. Amendments to orders are authorized "in the same manner and subject to the same conditions as an original order," with one important limitation. No change in the formula for allocating production can be made without unanimous consent of operators and royalty owners. There is an exception to this exception permitting the chief, by order (subject to the procedural and substantive requirements of other unitization orders) to enlarge the unit area. When he does so, however, the original unit area is to be treated as a single tract and production from the new unit is to be allocated to such tract in gross, and then further allocated to the leases in the original unit in accordance with the allocation formula of the original order.⁸³

The last paragraph of section 1509.29 negates the theory that unitization is a product of cross-conveyances between all owners of mineral rights in the pool. This theory has been used to explain how, under voluntary pooling and unitization agreements, royalty owners and operators share in production on land not owned by them before the unit was formed.⁸⁴ A principal consequence of the cross-conveyance theory is to require the joinder of all parties owning interests in the unit as defendants in any suit to remove a tract of land from the unit, the rationale being that all parties to the agreement own an interest in the land to be removed and would therefore be affected by an adverse judgment.⁸⁵ Other less

⁸³ For a discussion of the problems raised by enlarging a unit and the effect thereof on participation in production, see 6 Williams & Meyers, *Oil and Gas Law* § 980.4 (1964).

⁸⁴ 6 Williams & Meyers, *Oil and Gas Law* §§ 929-929.2 (1964).

⁸⁵ *Id.* § 929.1. See also *id.* §§ 928-928.5.

important consequences have been attributed to the cross-conveyance doctrine.⁸⁶ The last paragraph of section 1509.28 provides:

Except to the extent that the parties affected so agree, no order providing for unit operations shall be construed to result in a transfer of all or any part of the title of any person to the oil and gas rights in any tract in the unit area.

While the consequences of this enactment are nowhere stated in the statute, the abolition of the cross-conveyance doctrine can be attributed to a legislative intent to abolish some or all of the consequences of the doctrine. For example, it can be argued that since one important consequence of the cross-conveyance doctrine is the joinder requirement, and since the legislature must have known this when it took the trouble to deal with the doctrine, the joinder requirement was abolished by the negation of the cross-conveyance theory. Unfortunately, no positive rules on joinder are supplied by the legislation. The act leaves it to the courts to work out joinder requirements, albeit unembarrassed by the cross-conveyance doctrine.

Other consequences of the cross-conveyance theory are eliminated by the act itself, even without the express provision on the subject. By fabricating a statutory scheme for unitizing mineral properties through government order, the act sets at rest questions arising over the applicability of the Statute of Frauds, the Recording Act, and the Rule Against Perpetuities.

G. Effect on lease terms of compulsory pooling or unitization

When land under an oil and gas lease is pooled or unitized, the question arises as to the effect of such integration on the terms of the lease. Specifically, the questions are these: Does production on the unit satisfy the thereafter clause of a lease on land included in the unit? Do drilling operations satisfy the unless clause, the dry hole clause, the drilling operations clause and other savings clauses? Does payment of shut-in-gas royalty satisfy the shut-in-clause? Do prudent drilling operations on the unit satisfy the implied covenants of leases in the unit?

The answers to these questions depend, of course, on the provisions of the pooling or unitization agreement if the integration is voluntary, and upon the provisions of the statute or order if it is mandatory. Most voluntary pooling and unitization agreements provide that operations conducted anywhere on the unit and production from any part of the unit are deemed to be operations and production on any tract within the unit. Thus if Blackacre, a 160-

⁸⁶ *Ibid.*

acre tract of land owned by *A* and leased to *B*, is included in a drilling unit or field-wide unit operations plan, production from a well on Whiteacre, another tract of land in the unit, will satisfy the habendum clause of the lease on Blackacre. When the primary term of the lease on Blackacre expires, the requirements of the "thereafter clause" are met by the unit production on Whiteacre and the Blackacre lease is extended into the secondary term. Similarly, under the typical agreement, operations on the unit are deemed to be operations on Blackacre, so that the unless clause, the dry hole clause, the drilling operations clause, the shut-in-gas-royalty clause, and other such savings clauses in the Blackacre lease are satisfied by operations on the unit.

An agreement that unit operations and production will satisfy lease requirements on individual tracts is a perfectly understandable arrangement when the entire tract is included in the unit. In such case the lessor has agreed to accept operations and production on the unit as a substitute for operations and production on his particular tract, in return for royalty on production obtained anywhere on the unit—the lessor's share of royalty being based on the inclusion of *all* of Blackacre in the unit. Thus, lessors' participation in production may be based on surface acreage, value of the land for mineral purposes, acre-feet of productive sand or what have you; whatever the basis, all of Blackacre counts for something in the production allocation formula, and hence unit operations and production are sufficient to satisfy the lease terms as to all of Blackacre.

Where, however, only *part* of Blackacre is included in the unit, the above reasoning does not apply. The acreage excluded from the unit is not a factor in the production allocation formula, and the lessor gets no royalty for it. The question is presented whether or not operations and production on the unit nevertheless satisfy the lease terms as to the excluded acreage. Obviously, if in a voluntary arrangement the parties agree that the entire lease is preserved by unit operations, that is the end of the matter. Many agreements, however, are imprecise on this point, forcing the question to the courts for resolution.⁸⁷

As the following discussion will reveal, the Ohio statute raises the same problems of interpretation presented by many voluntary agreements. Its provisions are clear enough when the entire leasehold is included in the pooling unit or the unitization area; the statute is less clear when a portion of a leasehold is excluded from

⁸⁷ A detailed discussion of this question appears in 6 Williams & Meyers, Oil and Gas Law §§ 950-57 (1964).

the unit. Since the provisions relating to pooling differ from those relating to unitization, we will treat the two separately.

(1) Pooling.

The pooling section reads:

From and after the date of a pooling order, all operation, including the commencement of drilling or the operating of a well upon any tract or portion of the drilling unit, shall be deemed for all purposes the conduct of such operations upon each tract or portion thereof included in the drilling unit. That portion of the production allocated to a separately owned tract included in a drilling unit shall, when produced, be deemed, for all purposes, to have been actually produced from such tract.⁸⁸

Where all of a "tract" is within the unit, the statute clearly provides that operations and production are attributed to the entire tract. Thus the entire leasehold will be preserved by those operations on the unit that would preserve the lease if they were conducted on the leasehold in the absence of mandatory pooling.

Where part of a leasehold is excluded from the unit, we interpret the statute to attribute operations and production only to the included acreage. Whether or not the lease is preserved on the excluded acreage depends upon the conduct of operations and the securing of production on such excluded acreage. The key words of the statute in this respect are: "or portion thereof included in the drilling unit." In effect the sentence says that operations conducted anywhere on the unit are deemed, for all purposes, to have been conducted upon each tract,—or (if less than all the tract is included) upon that portion of each tract which is included in the unit. So far the paragraph seems unambiguous to us.

The second sentence is less clear. Read literally, the sentence simply doesn't speak to the situation of excluded acreage. It speaks only of production allocated to a "tract," by statutory definition, "a single, individually taxed parcel of land. . . ." ⁸⁹ Under the allocation provision of the statute, which employs included acreage as the exclusive basis for allocating unit production, no production is allocated to a statutory "tract," but only to a portion of a tract. If, therefore, the statutory definition of "tract" is discarded as inapplicable to the interpretation of this section, it could be forcefully argued that the quoted provision refers to production allocated to that part of a leasehold included in the unit, since the reference to "that portion of the production allocated to a . . . tract" invokes

⁸⁸ Section 1509.27 (last paragraph).

⁸⁹ Section 1509.01(J).

the statutory provision allocating production on the basis of included surface acreage. Thus it follows that the "deeming" provision attributes the production only to the included acreage, leaving the habendum clause of the lease on the excluded acreage to be satisfied by actual production thereon.

Moreover, the sentence itself speaks of production allocated to a "separately owned tract *included in a drilling unit . . .*"⁹⁰ The italicized phrase appears to be a qualification on the word "tract," even as defined in section 1509.01, and a qualification completely consistent with the mode of allocating unit production specified elsewhere in the statute. Lastly, construing the second sentence of the paragraph to attribute production only to included acreage makes it consistent with the first sentence, which clearly attributes operations only to the included acreage. We concede, however, that the second sentence (but not the first) can be interpreted to reach the contrary result. The argument would be that Blackacre, a 100-acre tract owned by A and leased to B, is a statutory tract; that the inclusion of 50 acres of Blackacre in the unit makes Blackacre "a separately owned tract included in a drilling unit"; and hence the production is deemed "to have been actually produced from such tract," namely, from all of Blackacre. This interpretation would, of course, attribute a different effect to operations from that attributed to production—a difficult distinction to justify.

There is available to us no legislative history to help solve this problem. The Armstrong Committee Report⁹¹ makes no mention of it, and the draft version of the bill is identical in this respect to the final version as enacted.

In construing the statute under these circumstances, it is permissible to consider the policy arguments on each side in an effort to discover the legislative choice. We believe that it is unfair and unsound for a legislature to declare that forced pooling of part of an oil and gas leasehold perpetuates the lease on the excluded acreage. It is unfair to the lessor, for it ties up the excluded land indefinitely without his consent and without his receiving any benefit from the lease on such land. It is unsound because there is no offsetting public gain. In fact the public interest is likely to suffer, for the excluded acreage is kept off the market as long as the unit well produces. The lessee may keep the lease without exploration or development of the excluded acreage; no one else can exploit the mineral potential of the land unless the lessee con-

⁹⁰ Section 1509.27 (last paragraph). (Emphasis added.)

⁹¹ Ohio Legislative Serv. Comm'n Report of the Comm. to Study Oil & Gas Laws in Ohio (1964).

sents, and he has no compelling incentive to consent. In short, to perpetuate the lease on the excluded acreage tends to inhibit the full exploration and development of potentially productive properties, to the detriment of both the landowner and the public.

For these reasons we believe the Ohio courts would be fully justified in finding that the last paragraph of section 1509.27 was intended to attribute operations and production to included acreage only and that such constructive operations and production preserve the lease on included acreage and not on excluded acreage. Under this interpretation of the statute, the lease is severed by the inclusion of only part of the leasehold in the unit; perpetuation of the lease on excluded acreage depends upon the terms of the lease and the actions of the lessee upon that portion of the leasehold, just as if pooling had never occurred, which, of course, it hasn't as to excluded acreage.

A contrary construction of the statute is so adverse to the interests of lessors that it is unfair (and perhaps violative of due process) to deny them the opportunity to be heard on the contents of the order and an opportunity to oppose promulgation of the order.

(2) Unit operations.

The relevant provision in the unitization section reads as follows:

Oil and gas allocated to a separately owned tract shall be deemed, for all purposes, to have been actually produced from such tract, and all operations, including, but not limited to, the commencement, drilling, or operation of a well upon any portion of the unit area shall be deemed for all purposes the conduct of such operations upon such separately owned tract in the unit area by the several owners thereof. The operations conducted pursuant to the order of the chief shall constitute a fulfillment of all the express or implied obligations of each lease or contract covering lands in the unit area to the extent that compliance with such obligations cannot be had because of the order of the chief.⁹²

The physical situation requiring construction of this provision is the same as it is in the pooling cases: A unit area has been established by order of the chief, and part but not all of Blackacre, which is subject to an oil and gas lease, has been included in the unit area. Where *all* of Blackacre is within the unit area the statute unequivocally attributes operations and production to Blackacre, thus preserving the lease on it.

While the wording of the unitization provision is different from that of the pooling provision, the issue still turns on the meaning

⁹² Section 1509.28 (fourth-from-last paragraph).

of the word "tract." The statutory definition in section 1509.01 seems to mean the entire leasehold, but the allocation provisions of section 1509.28(A)(3) seem to mean only the included acreage. The latter subsection directs the chief, in the absence of agreement, to "determine the value . . . of each separately owned tract in the unit area," and to allocate production in the proportion that the value of each tract bears to the total value of all tracts in the unit area. It seems clear that the words "tract in the unit area" mean that portion of the leasehold included within the unit, not the entire leasehold. It follows that the phrase "tract in the unit area" in the quoted paragraph means that portion of the leasehold included within the unit area.

Moreover, the last sentence supports the proposition that the lease is severed when only part of it is included within the unit area, since performance of express and implied obligations is satisfied by unit operations only to the extent that the unitization order precludes additional operations. Since the unitization order does not affect that portion of the leasehold outside the unit, the lease terms continue to govern the legal relationship of lessor and lessee as to such excluded acreage.

Again we concede that the language of the statute will bear a contrary interpretation and again we contend, for the reasons already advanced, that the better result is to find a severance of the lease.

H. *Secondary recovery operations*

Section 1509.21 provides that an operator

may apply to the chief of the division of oil and gas for a permit to conduct secondary recovery operations using any method approved by the chief. Such permit shall be in addition to any permit required by section 1509.05 [requiring drilling permits for all wells] Secondary recovery operations shall be conducted in accordance with such rules, regulations or orders of the chief as are necessary for protection of the public health and safety or conservation of natural resources.

Two questions are presented immediately by the wording of this section: (1) There being no statutory definition of "secondary recovery operations," what is meant by this term? (2) Is an operator required to obtain a permit to engage in secondary recovery, thereby subjecting his plan of operation to the chief's approval, or is the section merely permissive?

Secondary recovery has been defined as follows:

Broadly defined, this term includes all methods of oil extraction in which energy sources extrinsic to the reservoir are utilized

in the extraction. One of the early methods was the application of vacuum to the well, thus "sucking" more oil from the reservoir. The term is usually defined somewhat more narrowly as a method of recovery of hydrocarbons in which part of the energy employed to move the hydrocarbons through the reservoir is applied from extraneous sources by the injection of liquids or gases into the reservoir. Typically a differentiation is made between secondary recovery and pressure maintenance; the former involves an application of fluid injection when a reservoir is approaching or has reached the exhaustion of natural energy, while the latter involves an application of fluid injection early in the productive life of a reservoir when there has been little or no loss of natural reservoir energy. The fluid (water, gas or air) is injected into the formation through an input well and oil is removed from surrounding wells. Air and gas injections may follow either one of two procedures. In one, the air or gas is used to drive or flush the oil toward the output wells. In the other method the reservoir is repressured and during the pressure build-up period the flow from the output wells must be restricted. Natural gas is used very frequently for repressuring because it is very soluble in oil, thus increasing its volume, decreasing its viscosity, reducing its surface tension, and lightening its specific gravity—all desirable effects resulting in the expenditure of less energy in producing oil. Air, on the other hand, being only slightly soluble in crude oil, has little or no effect in reducing viscosity and surface tension of the oil and may actually oxidize some of the crude petroleum and aggravate corrosive action on equipment. In the typical water-flood project, there is an initial water-injection period of several months known as the fill-up before additional oil is forced into the producing wells. The end of this period is marked by a pick-up in oil production which is followed by a rapid increase in oil recovery. Combined oil and water production continues thereafter with the oil gradually decreasing and the water increasing until the economical limit of operations is reached. See Anderson, "Oil Production Methods," Hearings Before a Special Committee Investigating Petroleum Resources Pursuant to S. Res. 36, 79th Cong., 1st Sess. 308 (June, 1945); Williams, "Problems in the Conservation of Gas," *Second Annual Rocky Mountain Mineral Law Institute* 295 (1956). See also Water flooding, Fluid injection.

The term "secondary recovery" has been defined by a subcommittee of the American Petroleum Institute as "the oil, gas, or oil and gas recovered by any method (artificial flowing or pumping) that may be employed to produce them through the joint use of two or more well bores. Secondary recovery is generally recognized as being that recovery which may be obtained by the injection of liquids or gases into the reservoir for the purpose of augmenting reservoir energy; usually, but not necessarily, this is done after the primary-recovery phase has passed." American Petroleum Institute, *Secondary Recovery of Oil in the United States* 255 (1942).⁹³

⁹³ Williams & Meyers, *Manual of Oil and Gas Terms* 358 (1964).

Under this definition, a gas recycling operation, for example, would not be subject to the section. Nor would a pressure maintenance, salt-water disposal operation such as that in the East Texas oil field. The latter, however, is subject to section 1509.22. Classification of a particular operation as a statutory secondary recovery operation makes virtually no difference if the section is permissive only, and if it is mandatory, classification is important only in the case of those operations that can be carried on without unitization, for which a permit is needed in any event. As we shall see in the following paragraphs, almost all operations that might be classified as secondary recovery operations will usually require compulsory unitization.

Regarding the question of the necessity of obtaining a permit, the statutory language looks both ways. The clause, "may apply . . . for a permit," sounds permissive. The phrase, "using any method approved by the chief," sounds mandatory, for how can the chief approve the method unless a permit is first sought and why would a permit require approval if approval could be avoided by simply not seeking a permit? The second sentence is compatible with either interpretation. The third sentence points towards a requirement of a permit but can be read the other way. If the third sentence means, in effect, that no secondary recovery operation may be conducted except upon the chief's approval, then, of course, the first sentence permitting application for a permit is permissive only in the sense that one can conduct secondary recovery operations with a permit or not conduct them at all. If, on the other hand, the third sentence merely grants the chief power to issue general rules and regulations governing secondary recovery operations, the entire section could be construed as permissive. An operator *may* apply for a permit if he wishes to do so, but he is free to conduct secondary recovery operations without a permit, so long as he abides by the general rules and regulations applicable to all secondary recovery operations. A drilling permit will be necessary, however, if the recovery operation requires the drilling, deepening, or plugging back of a well, because of section 1509.05.

The legislative history of section 1509.21 provides no help in determining whether the section is mandatory or permissive. The Armstrong Committee Report⁹⁴ does not mention secondary recovery operations. The Staff Research Report⁹⁵ describes secondary recovery operations generally but contains no discussion of, or recommendation on, the necessity of a permit.

⁹⁴ *Supra* note 91.

⁹⁵ Staff Research Report at 29-32.

Although the question is not free from doubt, we conclude that the legislature intended to make the permit mandatory. To construe the statute as permissive makes little sense, for under that construction, with a permit one can carry on only those secondary recovery operations approved by the chief but without a permit can conduct any kind of operation he chooses. In opposition to this interpretation, it might be argued that the section is permissive and that the purpose of a permit is to provide a shield against federal antitrust proceedings with the *quid pro quo* for obtaining such protection being approval of the recovery method by the chief. According to this theory, Ohio says that we will erect the barrier of local public policy against antitrust actions if you get a permit,⁹⁶ but we will allow you to go ahead without a permit if you wish, though you take the antitrust risk if you do so. This analysis is unconvincing for it assumes that the antitrust danger is significant and that the state permit minimizes the danger—both very doubtful propositions. No antitrust proceedings have ever been brought against operators who entered into a unit agreement for secondary recovery operations,⁹⁷ and if such agreements are subject to the antitrust laws, it seems unlikely that the Ohio statute, so construed, would provide a defense. Under a construction of the statute as permissive, Ohio has not asserted a strong interest in secondary recovery; it has merely said, you can do it any way you wish without a permit, but you must do it our way with a permit. We doubt that this is a sufficient assertion of state concern to justify conduct otherwise illegal under the antitrust laws.⁹⁸

More plausible to us is a construction of the section as mandatory. The state has a legitimate conservation interest in all secondary recovery operations. One method of operation might

⁹⁶ Section 1509.41 provides: "No combination of persons or interests authorized by any provisions of Chapter 1509. of the Revised Code shall be construed to be a trust, monopoly, or other combination in restraint of trade prohibited by law." Such a provision is commonplace in compulsory unitization statutes. See 6 Williams & Meyers, *Oil and Gas Law* § 913.18 (1964).

⁹⁷ The only federal antitrust proceeding brought against any unitized operation was *United States v. Cotton Valley Operators Comm.*, 75 F. Supp. 1, 77 F. Supp. 409 (W.D. La. 1948), *affirmed*, 339 U.S. 940 (1950). This was a gas recycling operation—not a secondary recovery operation—and the government's attack was directed at what was alleged to be the joint processing, refining, and sale of the liquid constituents in the wet gas at fixed prices through agreed-upon trade channels, which allegedly eliminated competition. See Myers, *The Law of Pooling and Unitization* § 12.03 (Supp. 1965). See also *Hardwicke, Antitrust Laws, et al v. Unit Operation of Oil or Gas Pools* (2d ed. 1961).

⁹⁸ To obtain protection under *Parker v. Brown*, 317 U.S. 341 (1943), a stronger state policy than this is probably necessary.

recover as much as 80 per cent of the oil remaining in the ground while another might recover only 20 per cent while rendering the remainder either physically or economically unrecoverable. A legislature could well decide to grant the conservation commission power to forbid the less efficient operation.

Puzzling as section 1509.21 is that its interpretation may never be subject to litigation. If the chief does not assert the necessity of a permit, there is no one to complain. If the chief does assert the need for a permit, few operators will be in a position to challenge his ruling. If the secondary recovery plan requires the drilling, deepening, or plugging back of any well, the operator must have a permit under section 1509.05. The chief can make his views on the method of secondary recovery known in acting on this application. If the success of the operation depends upon subjecting a non-consenting owner to a unit operations plan, the approval of the chief is again necessary in order to obtain compulsory unitization under section 1509.28. Only where the secondary recovery operation can be conducted without any drilling and where all necessary parties in interest have voluntarily joined the plan can an operator afford to contend that he may proceed without the chief's approval. And even here, the chief can probably thwart the operator by an order issued under the third sentence of section 1509.21. In the final analysis, then, it appears to us that state control of secondary recovery operations in Ohio is squarely up to the Chief of the Division of Oil and Gas.

III. ADMINISTRATIVE PROCEDURE

Our examination of this topic will be brief as we lack familiarity with Ohio administrative law. A few comments on the procedural aspects of the new statute may nevertheless be appropriate. As previously noted, the chief is given power to "make, adopt, repeal, rescind, and amend . . . rules and regulations for the administration, implementation, and enforcement of Chapter 1509. of the Revised Code [the conservation act]." ⁹⁹ The procedure for making rules is set forth in chapter 119 of the Ohio Revised Code, which the conservation act expressly makes applicable to the chief's rule-making power. Apart from the procedural requirements of chapter 119, the conservation act itself prescribes some procedures to be followed in respect to particular kinds of orders. Special field spacing orders can be issued only after a hearing, and amendments thereto also require a hearing.¹⁰⁰ Notice of an opportunity to be heard must precede the issuance of a mandatory pooling order,

⁹⁹ Section 1509.03.

¹⁰⁰ Section 1509.25.

although here a hearing is necessary only if requested.¹⁰¹ Before any proposed plan of unitization can become the subject of a compulsory order, a hearing must be held on the plan. The chief can, upon his own motion, initiate the hearing, and he must do so if persons holding leases on 65 per cent of the land overlying a pool request one.¹⁰² Amendments in a unitization plan also require hearings.¹⁰³

At least two methods of obtaining review of an order are recognized by the conservation act. One route is to the Oil and Gas Board of Review. Section 1509.36 provides that "any person claiming to be aggrieved or adversely affected by an order by the chief of the division of oil and gas may appeal to the oil and gas board of review for an order vacating or modifying such order." The filing of an appeal does not automatically stay execution of the chief's order, but the board has discretion to order stays as it deems appropriate.¹⁰⁴ The board has power to subpoena witnesses and records and to rule on the admissibility of evidence. The statute apparently does not contemplate the board's review being limited to the record made before the chief, for section 1509.36 provides that "Either party . . . may submit such evidences [*sic*] as the board deems admissible." The standard of review prescribed by the statute is "lawful and reasonable"; if the order meets the standard, it is to be affirmed; "if the board finds that such order was unreasonable or unlawful, it shall make a written order vacating the order appealed from and making the order which it finds the chief should have made." This procedure is uncommon, for most producing states vest exclusive power to make and amend rules in the regulatory commission, without provision for an intermediate appeal to an expert commission. In those states, agency orders are ordinarily reviewed solely by the courts, which by constitutional, legislative, or self-imposed rule view their function as limited to sustaining or overturning the questioned order but not revising it.¹⁰⁵

¹⁰¹ Section 1509.27.

¹⁰² Section 1509.28(A).

¹⁰³ Section 1509.28(B).

¹⁰⁴ Section 1509.36 (fifth paragraph).

¹⁰⁵ See, e.g., *Continental Oil Co. v. Oil Conservation Comm'n*, 70 N.M. 310, 373 P.2d 809, 18 O. & G.R. 69, (1962); *Halbouty v. Railroad Comm'n*, 163 Tex. 417, 357 S.W.2d 364, 16 O. & G.R. 788, *cert. denied*, 371 U.S. 888 (1962); *Atlantic Ref. Co. v. Railroad Comm'n*, 162 Tex. 274, 346 S.W.2d 801, 14 O. & G.R. 362 (1961). See also Williams, "Nature and Effect of Conservation Orders: Their Finality, Modification, Restriction on Production and Consequences of Violation—Duty of Lessees," *Eighth Annual Rocky Mt. Mineral Law Inst.* 433, 441-42 (1963).

It is worthwhile for Ohio lawyers to note that the statute before the court in the *Continental* case, N.M. Stat. Ann. § 65-3-22(b) (1953), provided that: "the court [shall on review of a commission order] . . . enter its order either affirming, modifying, or vacating the order of the commission." The New Mexico Supreme Court held

Orders of the board are final unless vacated by the Franklin County Court of Common Pleas in a proceeding to be discussed hereafter.

This description of the board's powers, its ability to amend and revise conservation orders issued by the chief, the vague standard of review (lawful and reasonable), and the finality of the board's orders, indicates the importance the board could have in the administration of petroleum conservation in Ohio. Unfortunately, a board that meets infrequently, only to hear appeals from agency orders, and whose members receive only 20 dollars a day for their services, is not likely to have the constructive influence on the conservation regime that such an institution might have. The board may turn out to be another example of a good idea killed by parsimony.

The board's position is further weakened by the last paragraph of section 1509.36, which provides that appeals to the board "do not constitute the exclusive procedure [that a complainant] . . . must pursue in order to protect and preserve such rights, nor do such sections [of the conservation act relating to appeals to the board] constitute procedure which such person must pursue before he may lawfully appeal to the courts" We are not well enough versed in Ohio administrative law to say what other avenues of review this provision contemplates. But unless other modes of appeal are disadvantageous in comparison with an appeal to the board, it would seem, at least from this distance, that this section further undermines the authority and utility of the board.

When review by the board is the appeal route taken, the board's orders are subject to review by the Franklin County Court of Common Pleas.¹⁰⁶ This court's review is limited to the record made before the board, except that additional evidence is admissible if the court is satisfied that it is newly discovered and could not with reasonable diligence have been ascertained before the board hearing. The standard for determining the validity of the board's orders is the same as that used by the board in passing on the chief's orders—"lawful and reasonable." Moreover, the court seems to be given the same power as the board has to amend or revise the chief's orders. The last paragraph of section 1509.37 directs the court, if it finds the board's order unreasonable or unlawful to "make the order which it finds the board should have made." Since the board is directed to make the order the chief should have made, it seems to follow that the court can amend or revise the chief's orders, thereby making the order that the board ought to have

that the attempt to delegate power to the courts to modify commission orders violated the New Mexico Constitution.

¹⁰⁶ Section 1509.37.

found that the chief should have made.¹⁰⁷ Appeals from the Franklin County Court of Common Pleas are governed by the ordinary rules of procedure, there being no special provisions on the subject in the conservation act.

IV. RECOMMENDATIONS

From time to time we have noted some shortcomings of the new conservation act. It is perhaps appropriate, by way of a conclusion, to review some of these deficiencies briefly and systematically and to offer our suggestions for amendatory improvements in the legislation. Our standard for judging the legislation is the ideal; we readily concede that this Olympian detachment may be far removed from the real world of Ohio politics. It may well be claimed that the Ohio Legislature produced the best conservation act that could be obtained under the circumstances; we are in no position to judge that claim, but we do assert that the statute falls short of providing full authority to achieve maximum conservation of petroleum resources, that it fails to provide fully for protection of correlative rights, and that the administration of the act could have been made simpler and more effective.

Generally speaking, the deficiencies of the act fall into two categories: (1) ambiguities are present in the statutory language that will produce uncertainty in administration and unnecessary litigation; and (2) substantive rules have been adopted that derogate from sound conservation practice, and, correlatively, provisions are lacking in the act that would accomplish a greater degree of conservation and provide more protection for correlative rights.

Falling into the category of ambiguous provisions that will cause uncertainty of administration and unnecessary litigation are the following:

1. The last paragraph of section 1509.25 by denying the chief power to establish drilling units in accordance with a grid coordinate system renders uncertain the basis on which the chief is to fix spacing units for particular reservoirs. The act should be amended to allow the chief to establish spacing units by reference to any survey system he finds convenient. It seems unlikely that the chief would abuse this discretion by departing from existing surveys where they can be satisfactorily employed as the basis for a spacing order, for to do so is to make unnecessary work for the division.

¹⁰⁷ We mention again the question whether, under the Ohio Constitution, the courts can be delegated such supervisory power over orders of administrative agencies. See note 105 *supra*.

2. Section 1509.26 should be amended to make clear the position of lessors when lessees agree to pool voluntarily. As the section now stands, it is uncertain whether or not royalty interests are pooled by force of the statute when voluntary agreement is reached by the operators. We see no objection to a rule that pools royalty interests without the consent of their owners where production is allocated on the basis of surface acreage and where pooling does not affect leasehold acreage excluded from the unit. The act can be read to reach this result and could properly be amended to require it. But no harm is done by clarifying the section to reach the opposite result, *i.e.*, that voluntary pooling requires the consent of lessors, since lessors can be forced into a compulsory unit under section 1509.27.

3. The next-to-last paragraph of section 1509.27, dealing with the sharing of drilling expenses and production when a pooling unit is formed after a well has been drilled, lacks clarity. While we believe the legislature intended for the division of production and remaining unrecovered expenses to begin on the effective date of the pooling order, there is some uncertainty on the matter. The act should be amended to clearly provide for the rule stated above.

4. Section 1509.28(B) fails to make clear the method of counting royalty owners' votes on a proposed compulsory unitization order. We have contended that voting should be based on the number of royalty acres owned by the voter. Although the legislature probably intended this, the statute should be amended to specify this procedure.

5. Both the pooling and unitization sections should be clarified with respect to the effect of operations and production on oil and gas leases on land excluded from the pooling unit or unitization area. The statutory language points in the direction of severing such leases, *i.e.*, leaving the lease on the excluded acreage to be satisfied by operations and production on such acreage. An amendment specifying this result is needed.

6. Section 1509.21 should be amended to require a permit for conducting secondary recovery operations: the granting of such permit to be subject to the chief's approval of the method of secondary recovery. As the section now stands, the necessity of a permit is in some doubt, although the chief can probably reach most secondary recovery operations through some other section of the act.

Substantive deficiencies arising from inclusion of improper provisions and omission of needed provisions include the following:

1. State-wide and special field well-spacing orders ought to be issued solely on the authority of the Chief of the Division of

Oil and Gas, the veto power of the Technical Advisory Council should be abolished, and the statute should specify the standard for well-spacing to be the area that can be efficiently drained by one well. Optimum allocation of resources demands the elimination of unnecessary drilling. This is more likely to be accomplished if an impartial, expert administrative agency is given exclusive power to establish spacing units in accordance with the standard of efficient drainage.

2. Sections 1509.24 and 1509.25, relating to well-spacing orders, should be amended to broaden the purposes for which such orders may be entered. Section 1509.24 now limits the purposes of state-wide spacing orders to those "of conserving oil and gas reserves and [protecting] the safety of persons" An added purpose should be the prevention of unnecessary drilling. Similarly section 1509.25 permits a variation of the state-wide spacing pattern in particular fields only if the chief finds that the variation is "reasonably necessary to protect correlative rights or to provide effective development, use or conservation of oil and gas" This unduly limits the chief's power to vary spacing patterns from field to field. As stated above, the appropriate standard for fixing spacing units should be the area that can be efficiently drained by one well. The chief should have power to fix the spacing pattern for each field on the basis of this standard, without regard to the statewide pattern. Again, this purpose could be accomplished by giving the chief power to issue field well-spacing orders to prevent the drilling of unnecessary wells.

3. Corresponding changes should be made in section 1509.28, which authorizes compulsory unitization only if the operation "is reasonably necessary to increase substantially the ultimate recovery of oil and gas" Compulsory unitization can contribute significantly to the optimization of resource allocation by reducing the number of wells necessary to drain the reservoir through scientific location of those wells that are drilled. The statute should authorize the use of compulsory unitization for this purpose.

4. The last paragraph of section 1509.20, which denies the chief power to prevent the flaring of casinghead gas when "there is no economic market at the well for the escaping gas," should be repealed. The chief should have the discretionary power to encourage pipeline connections to wells producing casinghead gas.

5. As a corollary to (4), and for other purposes as well, the chief should be given general rule-making power to prevent waste, as defined in section 1509.01.

6. The non-consent penalty of section 1509.27 should be made discretionary with the chief, and additional options should be made

available to the non-consenting operator at the chief's discretion. Broad flexibility in solving the problem of nonparticipating operators could be achieved by granting the chief authority to order, as warranted by the circumstances, a nonparticipating operator to transfer his lease to the unit operator upon terms set by the chief, based upon the market value of the lease, or to pay out of production a non-consent penalty as fixed by the chief on the basis of the risk undertaken by the unit operator in drilling the unit well.

Similar provisions should be added to the unitization section if its provisions should be broadened to include undeveloped fields.

7. Section 1509.40 should be repealed and a new section enacted that prohibits curtailing production on the basis of market demand. If this is done and if the chief is given general rule-making power to prevent waste, there would be clear authority to regulate gas-oil and water-oil ratios to prevent dissipation of reservoir energy. Such power is somewhat in doubt at the present time.

8. In connection with the repeal of section 1509.40 and the substitution of an anti-market demand statute, there should be enacted ratable-take and common-purchaser statutes applicable to both oil and gas. These statutes are designed to protect correlative rights by preventing producers with a market from draining neighbors with a smaller market or with no market at all. Common-purchaser statutes accomplish the same objective by prohibiting discrimination among producers by purchasers.¹⁰⁸ The problem is ordinarily more serious with gas than with oil but standby authority should be available even for oil. The ability to prosecute discriminatory purchasers of oil may be enough to induce ratable purchase. Regarding gas, achieving ratable production is complicated by the Supreme Court's decision in *Northern Natural Gas*.¹⁰⁹ Nevertheless, for gas not subject to Federal Power Commission jurisdiction, common-purchaser statutes are still enforceable, and unless the Court extends *Northern Natural Gas*, ratable-take orders applicable to jurisdictional gas but directed at producers only are valid.

In summary, Ohio has made a satisfactory beginning effort to conserve petroleum resources and to protect correlative rights in petroleum reservoirs. The statute has deficiencies in both form and substance, and the correction of these should engage the legislature's attention in the coming years.

¹⁰⁸ Ratable-take and common-purchaser statutes and regulations are discussed in Stayton, "Proration of Gas," Fourteenth Annual Inst. on Oil and Gas Law and Taxation, Southwestern Legal Foundation 1 (1963).

¹⁰⁹ *Northern Natural Gas Co. v. State Corp.* Comm'n, 372 U.S. 84 (1963). The operation of ratable-take and common-purchaser orders in preventing net noncompensated drainage, the effect of the decision on such orders, and some of the implications of the opinion are discussed in Meyers, "Federal Preemption and State Conservation in *Northern Natural Gas*," 77 Harv. L. Rev. 689 (1964).